nexen

CHOICE

08

2008 SUMMARY REPORT

Every day our offices are lit
with people making choices
that drive home our strategy
and your investment.

STRATEGY OF CHOICE

CHOICE: it's what companies and investors value most in challenging times. Whether it's how we allocate capital, fund our growth, or decide which projects make most sense given current economic winds, choice is key.

We are a Canadian-based oil and gas company with operations worldwide. Our strategy is simple—build a sustainable energy company focused in three areas: oil sands, unconventional gas, and select conventional exploration and exploitation.

To be sustainable, we must be better than average. So we invest where we see the greatest opportunity to create long-term value—then we build enviable land positions, deploy expertise and apply technological solutions that give us a competitive edge.

Our strategy is proving successful. With North Sea Buzzard and Long Lake now adding to more than a decade of value from Yemen, we're moving into our next generation of projects: Usan offshore West Africa, discoveries in the Golden Eagle area of the North Sea, Horn River shale gas, future oil sands phases and exploration in key offshore basins worldwide.

See how our choices turn opportunities into legacy assets.


No Nexen debt to repay
before 2012

LIQUIDITY TO GROW

Assets alone don't deliver value—advantages do. And the tight credit markets are highlighting one of our greatest competitive advantages—our financial liquidity. While some companies scramble to secure financing to fund their projects, we have the financing in place to fuel our growth at our own pace.

Our decision to go to the financial markets in 2007 to secure 30-year debt is paying off. Today, our balance sheet remains healthy and we have no debt repayments before 2012. The average term to maturity of our debt is 19 years. Plus we have over $3.5 billion in cash and committed lines of credit to draw on if we choose.

With solid financial capacity, we can also take advantage of opportunities as others are forced to sell attractive assets to shore up their balance sheets. In December 2008, we acquired an additional 15% interest in Long Lake and became operator of the upgrader—all for less than cost. Choices like this make great strategic sense, and we are on the hunt for more outstanding deals that build on our advantages.

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FINANCIAL STRENGTH

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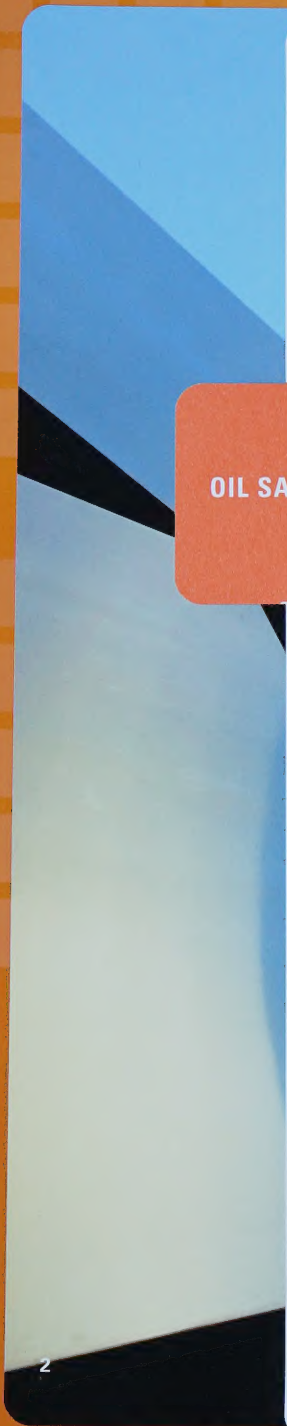


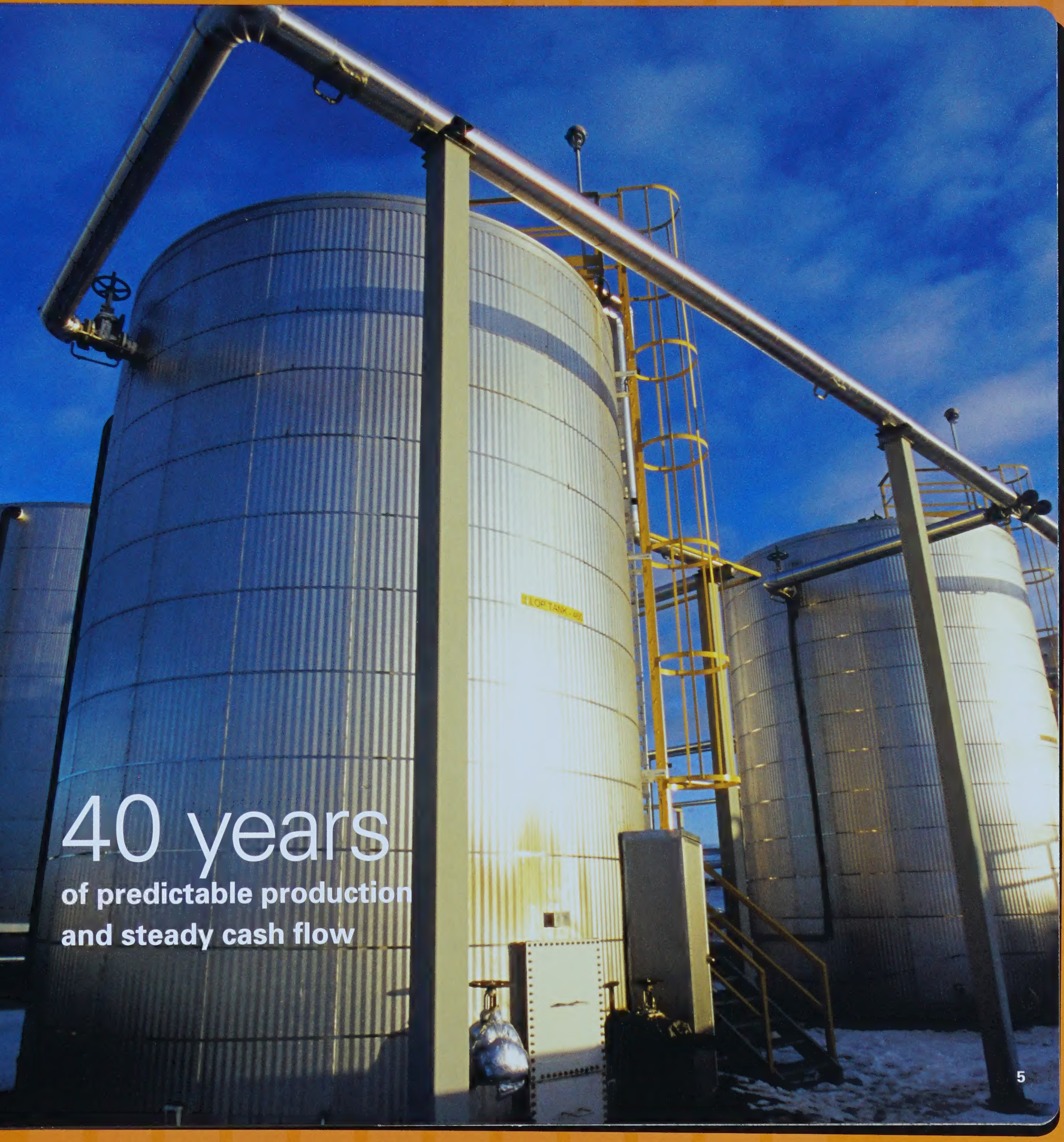
OIL SANDS

PLAYING IN THE BIGGEST SANDBOXES

In this game, access to resource is key. The bigger the sandbox, the more sustainable the business—especially when you leverage technology, expertise and talent to create value. The Athabasca oil sands is the world's second largest hydrocarbon basin. So, to be a world player in the energy industry, we believe it's key to be a leader in the oil sands.

Not only do we have the fifth largest resource here, we also have an integrated SAGD and upgrading solution that will deliver the highest-quality synthetic crude oil in North America at a cost that is cheaper than the competition. This means we suffer the least in low oil price environments and benefit the most when prices recover.

With no exploration risk, our oil sands project is unique from the rest of our portfolio. The resource is known and the technology to recover it is proven. The first phase—just 10% of our total resource—is now up and running. Given our significant land position, we can replicate Long Lake Phase 1 up to nine more times, with each phase designed to provide predictable production and steady cash flow for 40 years.



40 years

of predictable production and steady cash flow

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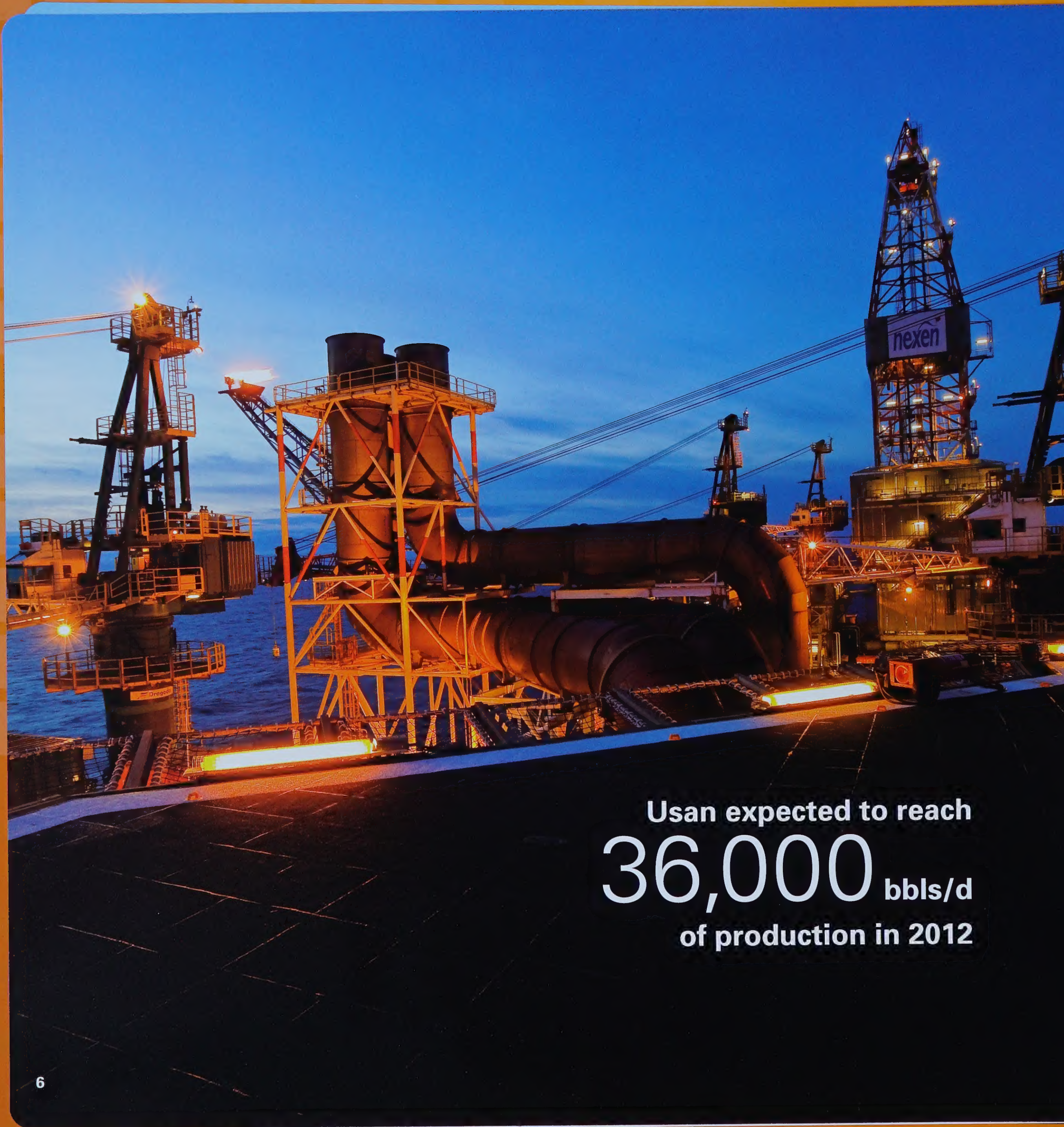


Usan expected to reach

36,000 bbls/d

of production in 2012

ON THE HUNT FOR MORE

Next to people, reserves are our most significant asset. Yet, what we produce today is gone tomorrow. So we are constantly on the hunt for more.

We still see huge value in conventional exploration and exploitation in select basins. As the world's easy-to-find oil is being depleted, exploration efforts are heading offshore and into deeper waters. We believe the smart choice is to focus our programs in familiar territory, namely the deep-water Gulf of Mexico, the North Sea and offshore West Africa. Here we've had past success, we hold significant acreage, infrastructure exists and great potential remains. Third-party studies confirm we are headed in the right direction. Over the past decade, these three basins have ranked top ten in the world for adding value from exploration.

Our Usan development, offshore West Africa, is a great example of value created through the drill bit. With hundreds of millions of barrels to produce, it is expected to come on stream in 2012 and boost our oil production by about 36,000 bbls/d. And there's a lot more to explore in the area.

7

CONVENTIONAL

UNCONVENTIONAL GAS

ANTICIPATING WHAT'S NEXT

To build a sustainable energy company, we must anticipate what's next. As conventional oil and gas reserves decline, attention is turning to unconventional gas plays such as shale gas and coalbed methane (CBM). Here we have to creatively use technology to get at the resource. We moved early into these plays in Canada, establishing attractive land positions that could not be replicated easily and affordably today.

The beauty of unconventional gas, particularly shale gas, is that it could fuel our short to medium term growth. Wells can be brought on stream at peak rates with short cycle-times. This type of development is a great complement to our conventional mega projects that can span many years from discovery to first oil. And the potential here is huge—enough to more than double the size of our company based on our current proved reserves. It also increases our exposure to gas, reducing our reliance on one commodity. The current economic slowdown is providing a great opportunity to test and perfect the most economical way to produce this asset and move toward commerciality. Stay tuned.


Shale gas could more than
double
our current proved reserves


Yemen achieved the
1 billion
barrel mark in 2008

LIVING THE LEGACY

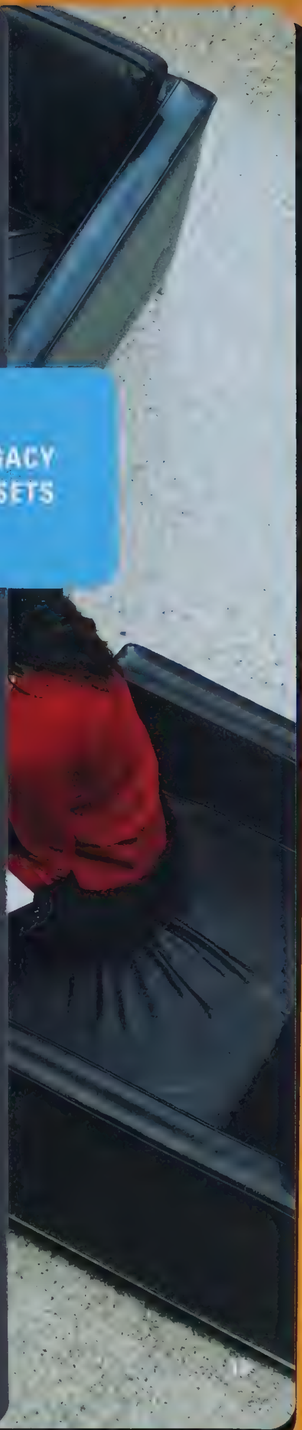
We're in the business of creating legacy assets—those that generate a ton of value over their lifetime and usually more than we projected at the start. How's that possible? Over time, we grow our knowledge, fine tune our expertise and incorporate new technologies to improve efficiencies and recoveries.

Nothing tells this story better than Yemen. Originally pegged at 300 million barrels, this asset produced its one billionth barrel in 2008 after a decade of safe operations. We've become experts at everything from training a local workforce to building multi-billion dollar facilities—expertise that's transferable around our world.

Buzzard has also become a legacy. It was the single largest contributor to our record cash flow in 2008. And the asset is still growing. Since the acquisition in 2004, we have increased our reserves by almost 50% and extended the production plateau.

Living a legacy requires we give great care to the environment and safety of our people and local communities. As governments and partners see the way we do business around the globe, doors open for us. And the cycle will repeat: opportunity, advantage, legacy, value.

LEGACY ASSETS



11

CHOICE

TOMORROW'S VALUE

As you can see, our strategy is one of choice. It's not dependent on one asset, geographical basin or commodity. And in today's volatile environment, focused diversity is a good thing. It affords us stability and flexibility to allocate knowledge and capital—in sync with the economic world around us.

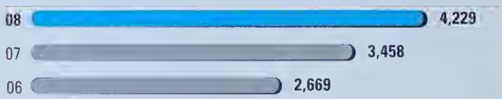
Globally, we are entering a new world of business. Tightened access to credit, re-pricing of risk and higher costs of capital are today's realities. As the global economy changes, we are adapting and growing stronger. We believe long-term demand for energy remains strong, and we are confident that our strategy focused on long-term value creation will build sustainable legacies.

Our people around the world will continue making choices that enhance our financial strength, build on our advantages and open doors to tomorrow's value. Most important, we'll do so in a way that balances our commitment to safety, the environment, social responsibility and transparent governance.

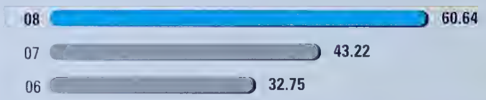
3,800 Nexen employees make value-creating choices every day

FINANCIAL HIGHLIGHTS

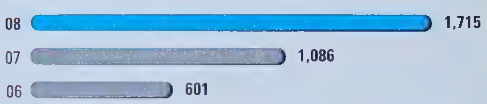
CASH FLOW
(Cdn$ millions)



CASH NETBACKS
(Cdn$/boe)



NET INCOME
(Cdn$ millions)



2008 CAPITAL

	2008	2007	2006
Cash Flow from Operations [1] ($ millions)	4,229	3,458	2,669
Cash Flow per Share ($/share)	8.04	6.56	5.09
Net Income ($ millions)	1,715	1,086	601
Net Income per Share ($/share)	3.26	2.06	1.15
Cash Netbacks from Oil and Gas Operations [2] ($/boe)	60.64	43.22	32.75
Capital Expenditures ($ millions)	3,066	3,401	3,330
Production before Royalties (mboe/d)	250	254	212
Production after Royalties (mboe/d)	210	207	156
Proved Reserves [3] (mmboe)	988	1,058	1,049
Proved + Probable Reserves [3] (mmboe)	2,036	1,964	1,651

1 *Defined as cash flow from operating activities before changes in non-cash working capital and other.*
2 *Defined as average sales price less royalties and other, operating costs and Yemen in-country taxes.*
3 *Represents our working interest before royalties using year-end pricing and includes our Syncrude reserves.*

Marvin Romanow
President and Chief Executive Officer

2008—A RECORD YEAR

Despite a volatile year, we delivered record financial results in 2008 fueled by record commodity prices, strong netbacks and solid production. Buzzard produced its one hundred millionth barrel in just two years and Yemen produced its billionth barrel. And at Long Lake, we produced our first premium synthetic crude in January 2009. With solid financial strength, we enter 2009 with an opportunistic focus aimed at building on our advantages.

In a year of unprecedented economic volatility, we achieved record financial results. Cash flow soared to $4.2 billion or $8.04 per share and net income topped $1.7 billion or $3.26 per share.

If ever there was a year that demonstrated the true peaks and valleys of being a price taker in this industry, 2008 was it. Oil began the year at around US$96/bbl, climbed to a record US$147/bbl, tumbled to a four-year low of just over US$35/bbl and then redeemed itself marginally to close around US$45/bbl. Combine these swings with a global credit freeze and demand slowdown, and you have a recipe for some tough times.

Despite this, our strategy continues to add value. To be a sustainable company, we must be able to thrive throughout the commodity price cycle, not just in high tides. Our view is that long-term supply and demand fundamentals will support higher prices. Just as US$147/bbl wasn't sustainable at the time, neither is US$40/bbl oil. Fortunately, we made a number of choices years ago that positioned us to weather this economic storm and ultimately come out ahead.

First, we have great financial capacity. I believe you obtain liquidity when it's available, not when you need it. We went to the credit markets in 2007 and secured 30-year debt at attractive rates. This was a great deal. Among Canadian industrial issuers, it is the largest 30-year tranche ever issued and one of the five largest investment grade debt deals done to date. Today, we have no immediate debt repayments, plenty of cash and committed lines of credit to draw on if we choose.

Buzzard Platform, UK North Sea

Second, we make money at low prices. Over the past several years, we've been steadily transitioning our portfolio away from mature declining basins toward new, high-value opportunities with lots of life ahead of them. We made significant investments in world-class mega projects like Buzzard and Long Lake. Today they are both delivering value. Buzzard proves it pays to go after high-quality barrels. Here, our quality differential, transportation and operating costs total about US$10/boe. So at today's lower prices, Buzzard still generates lots of cash.

Third, we are opportunity rich. We built significant land positions over the past several years in unconventional gas, oil sands and offshore exploration acreage—paying reasonable value for great potential. Now we have an asset mix that not only diversifies risk, it reflects our capacity to assess and seize a broader set of opportunities.

Looking forward, the question is not, "How do we survive low commodity prices?" but rather "How do we want to be positioned when prices and the economy recover?"

Now is the time to be doing our homework—perfecting upgrader operations, exploring the best solutions for shale gas extraction and scooping up great deals like the additional interest we acquired at Long Lake.

For 2009, we've crafted an oil and gas capital budget of $2.6 billion that is self-funded at WTI oil of US$60/bbl. Despite our strong financial position, we plan to approach 2009 with caution and maintain as much of our financial capacity as possible. We will focus our discretionary capital on projects that are economic in the current environment and proceed cautiously on others. Let me walk you through our choices.

Our legacy assets create the foundation for future growth. We expect both Buzzard and Yemen to continue generating significant value through 2009, contributing about 60% of our expected cash flow. To support base cash flow, we have secured put options on about 20% of our net production at US$60/bbl Brent oil.

Long Lake is another legacy asset in the making. I'm very pleased our integrated process is now proven and that we now operate both the upgrader and SAGD operations. Over the next year or so, we'll ramp up our share of premium synthetic crude volumes to 39,000 bbls/d and begin to see our $10/bbl cost advantage materialize.

While work will continue on Phase 2, we will wait to sanction it until at least 2010. By then we should have greater clarity on a number of fronts: Phase 1 performance, the economic environment and proposed climate change regulations. We are fully committed to developing the oil sands in a responsible manner. From a macro perspective, we see it as a key global source of long-term, reliable energy in a stable jurisdiction. And for Nexen, it provides an annuity-type profile to complement our lumpier value-adding growth elsewhere.

Our major development projects deliver step-change growth with great upside. Following Buzzard and Long Lake, the next major development to come on stream is Usan, offshore West Africa, expected in 2012. Despite long lead-times with multi-year development projects, we believe the initial step-change growth and incremental upside are worth the wait. Take Yemen for example. The billionth barrel produced in 2008 was more than three times our initial resource estimate. Buzzard is also growing. To date, we have increased our reserves by almost 50% since acquisition.

As the resource grows, so do our economies of scale. For years, our operating costs in Yemen were under US$2/bbl and Buzzard's are less than US$5/bbl. Offshore West Africa also holds much promise beyond Usan. While we estimate hundreds of millions of recoverable barrels at Usan alone, we see great potential in what surrounds it and are evaluating plans for further exploration here.

We believe exploration is a key ingredient to help fill our development pipeline. And our strategy is generating results. Our North Sea team is beating the odds, finding the prize more times than not. Our discoveries near our infrastructure at Buzzard, Scott/Telford and Ettrick allow for quick, economical tie-backs. Most exciting is the Golden Eagle area, where we have three discoveries and plans for additional drilling. We expect to fast-track development of the discoveries, which are economic even at today's low oil prices.

We'll also continue exploring in the deep-water Gulf of Mexico, a relatively under-explored basin. We have an enviable land position here and the rigs to drill our prospects. In 2009, we plan to appraise the potentially world-class Knotty Head discovery. Given discoveries can take years to bring on stream, we believe it's important to continue exploring through commodity price troughs.

A find today can be put into our development pipeline and brought on stream in a much stronger economy.

As conventional resources decline, attention inevitably turns to unconventional resources. Our choice to accumulate large tracks of shale gas lands in the Horn River basin of northeast British Columbia is proving its worth. Before we decide on commerciality, we need to get drilling costs down. So we'll spend the next year or two solving that equation. With an estimated 500 million to one billion equivalent barrels of potential here, this resource is worth unlocking.

We're well positioned to draw on our expertise from our other operations. Knowledge from Long Lake's successful drilling campaign will come in handy given the potential 1000 wells needed for shale gas. Plus our expertise in Yemen in reducing drilling costs will be valuable. The more we link our knowledge around Nexen's globe, the more valuable that knowledge becomes. We can speed up learnings and create superior solutions that put us a step ahead of the competition.

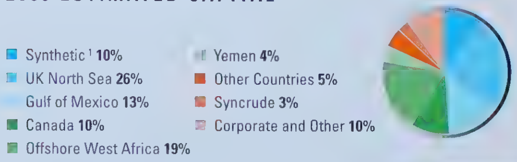
With all of these choices in hand, we are optimistic about our future. Throughout 2009, we must be flexible with both our capital programs and financial liquidity. We'll build our capacity so that we are ready to hit the ground running as the economy recovers.

OUTLOOK FOR 2009

Oil and Gas Capital Investment [1]	$2.6 billion
Production Before Royalties	255,000 – 270,000 boe/d
Production After Royalties	225,000 – 240,000 boe/d
Cash Flow [2]	$2.3 – $2.9 billion

1 *Excludes acquisition of additional 15% in Long Lake.*
2 *Assuming WTI averages between US$50/bbl and US$65/bbl.*

2009 ESTIMATED CAPITAL



1 *Excludes acquisition of additional 15% in Long Lake.*

People ask me "What's going to be different now that you are CEO?" While there's bound to be a natural evolution, a sustainable company cannot be about one person. I have a team of incredibly talented people who, in turn, lead powerful teams. My job is to hold the vision, ask the right questions, and make sure we're all moving in the same direction—always responsive to the environment around us.

I thank the Board of Directors for the opportunity to lead this innovative company, and I welcome their guidance. I'm inspired by all Nexen people who bring their ideas, enthusiasm and values to work each day. We know we have advantages to build on, and continued improvement is a priority to stay ahead. With smart choices, I'm confident we will endure this period of uncertainty and continue building shareholder value for years to come.

Marvin Romanow

President and Chief Executive Officer

NEXEN OPERATIONS WORLDWIDE

CANADA
Long Lake began producing premium synthetic crude in January 2009.

UK NORTH SEA
Buzzard generates over $1 billion in pre-tax cash flow at US$40/bbl WTI.

GULF OF MEXICO
We're a top deep-water leaseholder with numerous prospects identified and rigs secured to drill.

OFFSHORE WEST AFRICA
Usan has hundreds of millions of recoverable barrels and we see great potential around it.

While the current economic environment is challenging, Nexen is in great shape. We have globally-diverse assets, a strong financial position and choices to create value.

Q&A

Left to right:

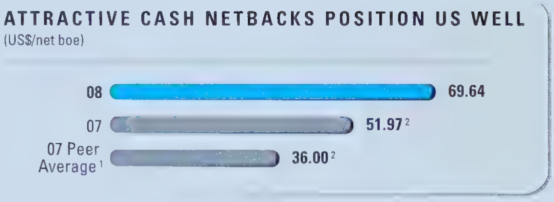
Larry Murphy Executive Vice President, International Oil and Gas

Roger Thomas Executive Vice President, North America

Kevin Reinhart Senior Vice President and CFO

At Nexen, decisions are made collectively and with due diligence. We draw on the unique expertise and perspectives of management and our people. Our management team is strong and dedicated to long-term value creation. After all, they are shareholders too, with a vested interest in ensuring Nexen's success.

Kevin Reinhart



1 Includes Canadian large cap exploration and production companies.

2 Sourced from JS Herold.

Q In 2008, the world experienced unprecedented financial turmoil. How has Nexen positioned itself to weather this storm and what will you do as the new CFO to ensure Nexen has sufficient financial resources for the future?

A Our financial position is very strong. Even after acquiring an additional 15% in Long Lake, we have over $3.5 billion in cash and available committed credit facilities and zero debt maturities for the next three and a half years. We built this liquidity during good times because when you actually need the cash during market downturns, it's often too late. Many companies with otherwise solid business models are now suffering because they don't have access to sufficient liquidity today.

Financial strength provides us with options. We can choose to continue to invest in organic projects that will generate value over the long term. We can also be opportunistic in acquiring valuable assets at attractive prices and we've consistently demonstrated our ability to do this. In the late nineties, we acquired interests in a number of deep-water blocks in the Gulf of Mexico, during a period of weak oil prices. We repeated this strategy in 1998 when we acquired a working interest in what has become our Usan discovery, offshore West Africa. And just recently, we acquired an additional interest in our Long Lake oil sands development for less than cost. We continue to look for similar opportunities in today's environment but we are mindful of the importance of not deploying our liquidity too early. We continue to monitor the financial landscape very closely and will adjust our capital spending as necessary.

We remain optimistic on commodity prices over the long term and believe our strategies will continue to generate value. We develop assets with long cycle-times and have structured our financing to manage short-term market volatility. By building liquidity in good times and taking a disciplined, counter-cyclical investment approach during downturns, we will not only endure the current financial turmoil, but also come out with a stronger portfolio of assets. Our financial strength affords us choices in a challenging environment.

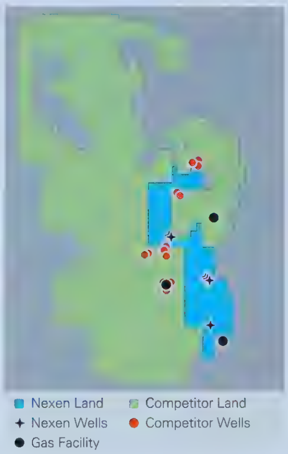
Roger Thomas

Q There has been a lot of excitement around shale gas in northeast British Columbia where Nexen has a significant land position. However, given growing North American unconventional gas supply and low natural gas prices, does this play really have the ability to be a company maker?

A The simple answer is yes. The resource potential that we see here is incredible—3 to 6 trillion cubic feet of contingent resource, which at the high end could double Nexen's proved reserves. We identified this play early so we managed to acquire a large contiguous land block at a good price. Since then, we have seen land prices increase almost tenfold.

However, there are certain things that we need to be able to do to make this play commercially viable. In this industry, we are price takers and therefore need to focus on what we can control—namely costs. For example, we need to reduce our drilling and completion costs by becoming more efficient. This is not something new to us. When you compare drilling costs in Yemen today from when we started, they have come down by more than 60%.

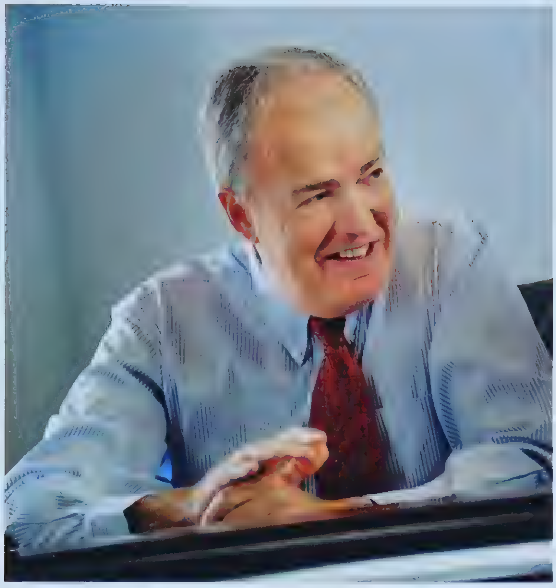
OUR SHALE GAS LANDS ARE IN THE HEART OF HORN RIVER BASIN



Infrastructure is another key to the development of the Horn River basin. Unlike the Barnett shale, this basin lacks significant pre-existing infrastructure. We have a producers group in place that is working together so we can better manage all development in the area and the infrastructure will come with time.

The Horn River play could add short cycle-time production to our company-wide portfolio, which typically has long cycle-time projects. In the Canadian division, it advances our strategy of transitioning from mature conventional fields to long-lived resource plays. Frankly, this play is a tremendous opportunity for Nexen.

The resource potential we see at Horn River is incredible. However, certain things must happen to make this play commercially viable.

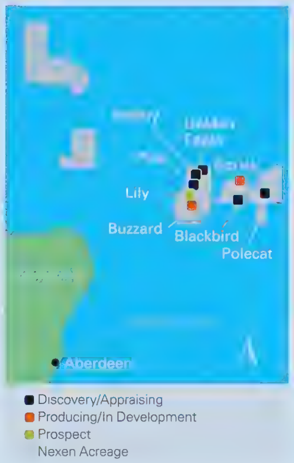


Larry Murphy

Q Internationally, Buzzard has been a huge success for Nexen. Offshore West Africa, the Usan development is well underway with first production expected in 2012. Where else do you expect to see growth in Nexen's international operations?

A Buzzard is clearly a legacy asset that continues to grow and exceed our initial expectations from when we acquired it. For example, we have increased our proved reserves by almost 50% and extended our production plateau by over three years. Our strategy is to grow production in the UK North Sea with smaller discoveries near existing infrastructure. This strategy is proving to be successful. Our next major development project is likely the Golden Eagle area. This area includes discoveries at Golden Eagle, Pink and Hobby, and we expect to drill our Lily prospect next. Plans to fast-track development of this area are also underway. And we are leveraging our knowledge of the North Sea basin into the Norwegian sector. We have ten offshore licenses there with plans to drill our first exploration well in the near future.

OUR NEXT MAJOR DEVELOPMENT IS LIKELY THE GOLDEN EAGLE AREA



Usan has allowed us to establish an exploration and production presence offshore West Africa. Besides the world-class discovery at Usan, we have captured significant surrounding exploration acreage and already made two smaller discoveries. This area has the potential to repeat the success of Yemen and Buzzard, and allow us to grow production here.

On the international stage, we are as good as anyone. We have an ability to select world-class projects, work with international governments and operate a geographically diverse portfolio. For example, we successfully pre-qualified for future oil and gas opportunities in Iraq. When we operate in any country, we take the concept of a 'Social License to Operate' very seriously. We recognize we are guests of the host nation and work to be a welcomed partner. Whether through the drill bit or a timely acquisition, we believe we can continue growing our international production.

UNDERSTANDING OUR OIL SANDS ADVANTAGE

NOT EVERY BARREL OF OIL IS EQUAL

The Athabasca oil sands resource is one of the largest oil deposits in the world—second only to Saudi Arabia. The challenge is unlocking the value of the resource in a responsible way. It's not enough to just be in the oil sands. To be a leader in developing this resource, we knew we needed a competitive advantage that sets us apart.

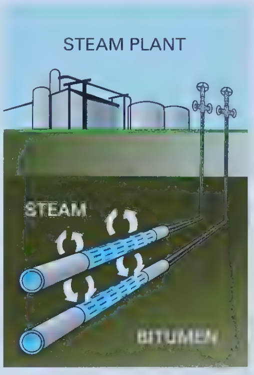
Today our integrated SAGD and upgrading solution produces the highest-quality premium synthetic crude (PSC™) at a substantial cost savings compared to competing processes. To understand our advantage, let's discuss the resource itself and the economic hurdles to producing it.

UNDERSTANDING BITUMEN

Oil sands or bitumen is a heavy tar-like substance that is trapped between the sands in the ground. Because of its heavy density (visualize a hockey puck), bitumen doesn't flow to the surface like conventional oil, so ordinary extraction technology doesn't work here. Some operations, like Syncrude, mine shallow bitumen with large trucks and shovels. But in other places, like on our oil sands leases, the bitumen is buried too deep—800 feet—for mining to be affordable.

GETTING THE OIL TO FLOW WITH SAGD

To get the bitumen to the surface, we chose steam-assisted-gravity-drainage technology or SAGD. In simple terms, SAGD uses steam to melt the bitumen so it can flow. To accomplish this, two horizontal wells are drilled about five meters vertically apart. As steam is injected into the higher well, the surrounding bitumen is heated and flows by gravity to the deeper well, which brings it to the surface. The bitumen is then processed to separate out the water, which gets recycled back into steam.



There are many advantages to SAGD operations. First, we can access our deeper bitumen resource. Second, SAGD operations have a smaller footprint on the earth's surface than open pit mines. That's because we drill multiple wells from a single pad. The sand stays underground and therefore we don't need to worry about large tailing ponds. Today, we have substantial experience in operating SAGD wells. In fact, once our operations are fully ramped up, we will be the world's largest SAGD producer.

THREE ECONOMIC HURDLES OF SAGD BITUMEN PRODUCTION	OUR CHOICES
1. High cost of natural gas	**Substantially Reduced.** We produce our own syngas for fuel from the bottom of the barrel that others throw away.
2. High cost of diluent	**Eliminated.** We upgrade our bitumen on-site versus needing expensive diluent to transport it to market.
3. Low realized bitumen price	**Eliminated.** Our bitumen is upgraded into PSC™ which typically sells at a premium to WTI oil.

We take the bottom of the barrel, which has no value, and apply technology to build a huge advantage.

Gary Nieuwenburg Senior Vice President, Synthetic Crude

UPGRADING FOR FURTHER VALUE

Bitumen is a low-value product that requires upgrading before going to the end user. If we were just a bitumen producer, we would have to buy expensive diluent (a thinner) to transport the bitumen to market. And then we would sell this low-value crude at a significant discount to WTI—which at today's low oil prices, wouldn't be worth the investment.

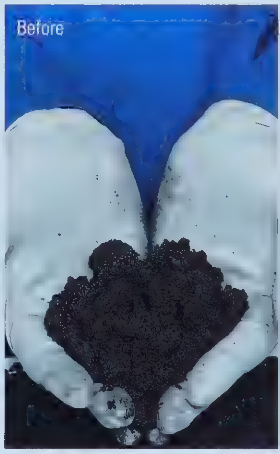
Our integrated process goes a few steps further to add a lot more value. First, we separate the bitumen into the top and bottom of the barrel. Partially upgraded bitumen forms the top and liquid asphaltenes form the bottom. Then, using a hydrocracker, the bitumen is further upgraded to the highest-quality synthetic crude on the market today. It will command a premium price. The bottom of the barrel is turned into synthetic gas as a source of fuel. We use that fuel to generate steam for the SAGD process, power for the upgrader, and as a hydrogen source for the hydrocracker.

FUELING OUR COST ADVANTAGE

Let's compare this to other upgrading operations. In a traditional process, the bottom of the barrel is turned into a solid, called coke, which is stockpiled or disposed of. We turn this portion of the barrel into a fuel source, which means we don't need to purchase large amounts of natural gas like our competitors do. And that's our biggest advantage. With NYMEX gas at US$6/mcf, we can generate a cost savings of around $10/bbl.

PROVING OUR TECHNOLOGY

For several months now, we have been converting the bottom of the barrel into syngas. In January 2009, we produced our first premium synthetic crude. These two achievements prove our process works. As we ramp up our Long Lake production over the next year or so, we will begin to see that $10/bbl operating cost advantage materialize. Then, as market conditions allow, we can begin developing additional phases.



Bitumen trapped in the oil sands

Long Lake PSC™ priced at a premium to WTI

A responsible approach

A hands-on demonstration teaches fire safety during a community event sponsored by the Long Lake Project and local volunteer fire department.

Value is not *just* measured in dollars or barrels. To be sustainable, we must engage all employees to make responsible choices—those we are proud to share with future generations. A broader vision of sustainable business practices has always been part of how we do business.

In 2008, we were included on the Dow Jones Sustainability World Index for the eighth consecutive year.

For an in-depth review of our sustainability, please read our Sustainability Report available June 2009 at www.nexeninc.com.

For our operations to be sustainable, they must deliver long-term value to our stakeholders. Our sustainability efforts include seeking ways to reduce environmental impacts, improving our safety record and partnering with communities to build capacity and create lasting value.

MINIMIZING ENVIRONMENTAL IMPACTS

As part of the Horn River Basin Producers group, we are engaging industry peers, government and community stakeholders to reduce the environmental footprint of industry activities by planning shared access roads and facilities. At Long Lake, our technology choices will enable us to more effectively participate in future carbon capture.

We also continued to be part of the global sustainability conversation by sponsoring and participating in the 19th World Petroleum Congress. In addition, The Carbon Disclosure Project recognized us for the quality of our 2008 voluntary climate change disclosure. Closer to home, approval for 15 sour gas wells and five pipelines northeast of Calgary was achieved without a regulatory hearing because of our successful two-year stakeholder consultation process.

IMPROVING HEALTH AND SAFETY

Health and safety are top priorities for Nexen. In 2008, we significantly improved contractor safety performance in our Canadian conventional drilling operations and came very close to achieving our best ever employee and combined employee-contractor safety performance worldwide. Our goal is zero incidents, so we are always looking to improve both employee and contractor safety.

We also conducted audits of our health, safety, environment and social responsibility management systems in our Synthetic and US business units. These audits help identify our strengths and areas where we can improve.

BUILDING LASTING ECONOMIC AND SOCIAL BENEFITS

We believe in partnering with the communities where we operate. In 2008, Nexen and OPTI marked the Long Lake commissioning by committing $2.5 million to support education initiatives in the area. In Yemen, we celebrated the 10th anniversary of our Yemen Scholarship Program, which provides funding for Yemeni students to complete post-secondary degrees in Canada. We also assisted when major flooding hit Yemen, providing $1 million for flood relief, as well as equipment and volunteer people power.

In building legacy assets, we will be part of local neighbourhoods for many years. We earn our place here by ensuring both Nexen and community members benefit from the value we create.

We comply 100% with all Canadian and NYSE requirements and guidelines for corporate governance disclosures.

See our proxy circular for specifics on our board committees, director and executive bios and their compensation.

We believe in good governance and transparent communication—not just in uncertain economic times, but as an ongoing conversation. Our Board of Directors sets the direction for governance, management provides the leadership, and employees integrate their values into actions every day.

A DIVERSE AND EXPERIENCED BOARD

Our directors oversee management to ensure we are making the best choices for creating long-term value responsibly. They are strong, experienced individuals with considerable skills and knowledge to strategically guide Nexen through economic highs and lows.

At year end, we saw the retirement of Charlie Fischer as Nexen's President and CEO and as a valued board member. Following our annual meeting in April 2009, two other dedicated directors, Dave Hentschel and Dick Thomson, will also be leaving. We thank all three gentlemen for their exceptional contributions to Nexen. We also welcome Marvin Romanow, our new President and CEO, William Berry and Robert Bertram to our Board. In choosing new directors, we ensure that our collective board expertise covers all areas of guiding an international, top-tier business. We are confident our Board is well equipped to guide Nexen's future.

Transparent and effective governance is key in the ongoing stewardship conversation between directors, management and shareholders.

COMPENSATION LINKED TO STRATEGY

With massive government bailouts in the United States, executive compensation has come under increased public scrutiny. At Nexen, our compensation for both directors and executives is linked to strategic business objectives, including increasing shareholder returns. Simply put, you benefit, they benefit. See our management proxy circular for complete details.

STAKEHOLDER ENGAGEMENT AND ETHICAL OPERATIONS

We are committed to meaningful, transparent communication and ethical business practises. We actively solicit dialogue with stakeholders on many fronts—from our Governance Roadshow, to community meetings with our neighbours, to third-party verifiers of our Sustainability Report. We also invite and address any concerns that come through our anonymous Integrity Helpline. Operating with integrity is essential to our long-term success. To that end, all Nexen people agree annually to comply with our Ethics Policy.

EXTERNAL RECOGNITION

While governance practices speak for themselves, external recognition helps reinforce what we are doing well and where we can improve. Below is recognition we've received on our 2008 governance:

- The Award of Excellence in Corporate Governance Disclosure from the Canadian Institute of Chartered Accountants;
- Recognition from the Canadian Coalition for Good Governance for new best practices in shareholder communications and compensation disclosure;
- The Best Corporate Governance Practices in North America by IR Global Rankings;
- Ranked 7th, scoring 92 out of 100, in the Report on Business corporate governance rankings; and
- A 10 out of 10 ranking from GovernanceMetrics International.

We believe that good governance is a journey, not an end point. When combined with a sound strategy, it will result in superior long-term value creation. We look forward to a continued conversation on our plans, choices and results.

Employees are rewarded with a competitive compensation package that values performance.

OUR GLOBAL FAMILY

Our Nexen family spans continents, cultures and communities. It is rich with opportunities to learn and create outstanding results. As we invest in our people, we invest in our future. So we believe in sharing knowledge across our organization and also across generations. Just as new projects, such as shale gas, incorporate learnings from our successes in Yemen and at Long Lake, employees across generations learn from each other.

For example, as new graduates join Nexen, they are rotated through a number of positions and groups. This helps them gain broader experience, clarify their interests and deepen their understanding of what it takes for Nexen to be successful. We also learn from new employees. They come with enthusiasm, fresh ideas, a tech-friendly approach and an insatiable desire to question the 'way we've always done things'.

Krystle Merkley is walking in her grandfather's footsteps. She's the latest generation in her family to work at our Balzac gas plant.

INNOVATION AT WORK

Nexen is a company that encourages 'possibility thinkers' who can see beyond current circumstances and create innovative solutions for value creation. To promote an innovative spirit, we encourage multi-disciplinary teams where not everyone thinks the same way. We also encourage movement throughout the company. We believe you can invest your whole career under Nexen's roof and experience a number of vastly different jobs around the globe.

VALUES MATTER

Many employees tell us what most attracted them to Nexen is our values and the responsible way we operate globally. Because Nexen doesn't exist without people, our values are really the collective values of our people. We live these each day—in how we conduct ourselves with ethics and integrity, operate safely, respect the environment, integrate stakeholder perspectives, support community initiatives and balance work and family life.

A career at Nexen is all about choices: to learn new skills, broaden experiences and add value that makes a lasting difference.

Proving up value

Buzzard Platform Since acquiring Buzzard, we have increased proved plus probable reserves by almost 50%.

Reserves give an investor a sense of our future production, but they don't tell our whole story. We have vastly more in our opportunity pipeline than what we are permitted to recognize as reserves. As we draw on our historical performance and 30-year track record of profitability, we'll prove up this value—from potential to profits.

We now have over 2 billion boe of proved and probable reserves, which represents a reserves life index of over 20 years. Yet there's more to come as our reserve bookings only reflect a fraction of the choices we have made. Take oil sands for example. So far we've booked 1 billion barrels of proved and probable reserves for Phases 1 and 2 of Long Lake—but we have enough resource potential to develop up to 10 phases. Our booked reserves also reflect little for our undeveloped discoveries in the UK North Sea, Gulf of Mexico and our unconventional CBM and shale gas plays in western Canada. As these projects take shape, we expect to book significantly more reserves, revealing the value of our choices.

BEFORE ROYALTIES, YEAR-END PRICING

	Oil and Gas Activities										Mining	
	International				United States		Canada					
	Yemen	United Kingdom		Other Intl								
(mmboe)	Oil	Oil	Gas	Oil	Oil	Gas	Oil	Gas	Bitumen	Total Oil and Gas	Syncrude[3]	Total Oil, Gas and Mining
Proved Reserves												
December 31, 2007	41	203	4	38	25	37	56	62	268	734	324	1,058
Extensions and Discoveries	1	5	–	–	–	1	2	6	19	34	8	42
Revisions–Performance	11	17	–	–	2	(3)	(2)	7	–	32	–	32
Revisions–Economic	–	(16)	–	(2)	(4)	(1)	(24)	(3)	–	(50)	–	(50)
Production	(22)[4]	(37)	(1)	(2)	(3)	(5)	(6)	(8)	(2)	(86)	(8)	(94)
December 31, 2008	**31**	**172**	**3**	**34**	**20**	**29**	**26**	**64**	**285**	**664**	**324**	**988**
Probable Reserves[1,2]												
December 31, 2007	15	139	5	60	39	21	24	34	523	860	46	906
Extensions, Discoveries and Conversions	(1)	(23)	–	–	–	(2)	1	(1)	209	183	–	183
Revisions–Performance	–	18	(1)	(1)	(17)	(1)	(8)	(6)	–	(16)	–	(16)
Revisions–Economic	(1)	(2)	–	2	(14)	(2)	(4)	(4)	–	(25)	–	(25)
December 31, 2008	**13**	**132**	**4**	**61**	**8**	**16**	**13**	**23**	**732**	**1,002**	**46**	**1,048**
Proved + Probable[1,2]												
December 31, 2007	56	342	9	98	64	58	80	96	791	1,594	370	1,964
Extensions, Discoveries and Conversions	–	(18)	–	–	–	(1)	3	5	228	217	8	225
Revisions–Performance	11	35	(1)	(1)	(15)	(4)	(10)	1	–	16	–	16
Revisions–Economic	(1)	(18)	–	–	(18)	(3)	(28)	(7)	–	(75)	–	(75)
Production	(22)[4]	(37)	(1)	(2)	(3)	(5)	(6)	(8)	(2)	(86)	(8)	(94)
December 31, 2008	**44**	**304**	**7**	**95**	**28**	**45**	**39**	**87**	**1,017**	**1,666**	**370**	**2,036**

1 *We internally evaluate all of our reserves and have at least 80% of our proved reserves assessed by independent qualified consultants each year; 90% were assessed this year. Our reserves are also reviewed and approved by our Reserves Committee and our Board of Directors. Proved reserve estimates represent our working interest using The Canadian Oil and Gas Evaluation Handbook (COGEH) standards modified to reflect Securities and Exchange Commission requirements and year-end constant pricing, but have been estimated on a before royalty basis. Gas is converted to equivalent oil at a 6:1 ratio.*

2 *Probable reserves have been prepared in accordance with COGEH standards using year-end constant pricing and are estimated on a before royalty basis. US investors should read the Cautionary Note to US Investors at the end of this report.*

3 *US investors should read the Cautionary Note to US Investors at the end of this report.*

4 *Production includes volumes used for fuel in Yemen.*

PERFORMANCE REVIEW

	2008	2007	2006	2005	2004
Highlights					
Net Sales [1]	7,424	5,583	3,936	3,932	2,944
Cash Flow from Operations [2]	4,229	3,458	2,669	2,403	1,942
Per Common Share ($/share)	8.04	6.56	5.09	4.62	3.78
Net Income	1,715	1,086	601	1,140	793
Per Common Share ($/share)	3.26	2.06	1.15	2.19	1.54
Capital Expenditures	3,066	3,401	3,330	2,638	1,681
Business Acquisitions	–	–	78	–	2,583
Dispositions	6	4	27	911	34
Production [3,4]					
Production Before Royalties (mboe/d)	250	254	212	242	250
Production After Royalties (mboe/d)	210	207	156	173	174
Financial Position					
Working Capital	2,503	412	476	29	40
Property, Plant and Equipment, Net	14,922	12,498	11,739	9,594	8,643
Total Assets	22,155	18,075	17,156	14,590	12,383
Net Debt [5]	4,575	4,404	4,730	3,639	4,285
Long-Term Debt	6,578	4,610	4,673	3,687	4,259
Shareholders' Equity	7,139	5,610	4,636	3,996	2,867
Shares and Dividends					
Common Shares Outstanding (millions)	519.4	528.3	525.0	522.2	516.8
Number of Registered Common Shareholders	1,624	1,569	1,454	1,294	1,329
Closing Common Share Price (TSX) (Cdn$/share)	21.45	32.10	32.10	27.71	12.18
Dividends Declared per Common Share (Cdn$/share)	0.175	0.10	0.10	0.10	0.10
Cash Flow from Operations [2]					
Oil and Gas					
United Kingdom	3,308	2,101	477	284	30
Yemen	638	664	877	929	581
Canada	389	179	229	397	426
United States	508	480	573	667	700
Other Countries	133	87	94	48	57
Marketing	(356)	73	432	138	100
Syncrude	400	319	240	223	183
	5,020	3,903	2,922	2,686	2,077
Chemicals	85	90	83	95	82
	5,105	3,993	3,005	2,781	2,159
Interest and Other Corporate Items	(292)	(350)	(254)	(335)	(196)
Income Taxes	(584)	(185)	(82)	(43)	(21)
Total Cash Flow From Operations	**4,229**	**3,458**	**2,669**	**2,403**	**1,942**

1 Represents net sales from continuing operations.
2 Cash flow from operations is defined as cash generated from operating activities before changes in non-cash working capital and other.
3 Production is Nexen's working interest share and includes our share of production from Syncrude.
4 Natural gas is converted at 6 mcf per equivalent barrel of oil.
5 Net debt is defined as long-term debt and short-term borrowings less cash and cash equivalents.

	2008	2007	2006	2005	2004
Production Before Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	99.7	81.2	16.9	12.6	1.5
Yemen	56.6	71.6	92.9	112.7	107.3
Canada	16.2	17.1	20.0	29.2	36.2
United States	9.3	16.4	17.0	22.2	30.0
Long Lake	3.9	–	–	–	–
Other Countries	5.8	6.2	6.3	5.6	8.0
Syncrude	20.9	22.1	18.7	15.5	17.2
	212.4	214.6	171.8	197.8	200.2
Natural Gas (mmcf/d)					
United Kingdom	18	16	20	23	3
Canada	131	118	108	124	146
United States	78	101	111	116	148
	227	235	239	263	297
Total Production Before Royalties (mboe/d)	**250**	**254**	**212**	**242**	**250**
Production After Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	99.7	81.2	16.9	12.6	1.5
Yemen	30.6	39.8	51.8	60.6	53.5
Canada	12.3	13.4	15.8	22.6	28.2
United States	8.1	14.5	15.0	19.6	26.5
Long Lake	3.9	–	–	–	–
Other Countries	5.3	5.7	5.7	5.1	7.2
Syncrude	18.2	18.8	16.9	15.3	16.6
	178.1	173.4	122.1	135.8	133.5
Natural Gas (mmcf/d)					
United Kingdom	18	16	20	23	3
Canada	109	98	91	101	115
United States	66	86	94	99	126
	193	200	205	223	244
Total Production After Royalties (mboe/d)	**210**	**207**	**156**	**173**	**174**
Oil and Gas Cash Netback Before Royalties[1] ($/boe)					
Producing Assets					
United Kingdom	87.70	67.85	55.53	42.93	39.19
Yemen	31.11	25.52	26.35	22.56	14.99
Canada	32.97	20.07	22.87	25.46	21.24
United States	56.42	42.28	40.42	45.85	35.35
Syncrude	53.83	41.94	37.86	43.34	31.07
Other Countries	86.58	61.94	57.71	49.18	28.55
Company-Wide Oil and Gas	**60.64**	**43.22**	**32.75**	**30.57**	**22.66**

1 *Defined as average sales price less royalties and other, operating costs and Yemen in-country taxes. Calculation details can be found in the Statistical Supplement on our website.*

EXECUTIVE MANAGEMENT

Marvin F. Romanow

President and Chief Executive Officer

Marvin has been with the company since 1990. Prior to being appointed President and CEO in January 2009, he was the Executive Vice President and CFO. Marvin's career has spanned many leadership roles in corporate finance, planning, business development, exploration and development, and reservoir engineering. He is a director of the Canexus Income Fund and the Canadian Energy Research Institute. He is a past board member of Syncrude Canada.

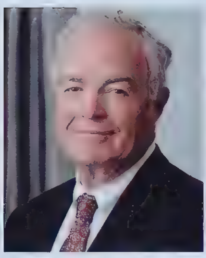
Marvin received his Bachelor of Engineering degree and MBA from the University of Saskatchewan.

Kevin J. Reinhart

Senior Vice President and Chief Financial Officer

Kevin joined Nexen as Controller in 1994. He held the positions of Director of Risk Management and Treasurer and then Senior Vice President, Corporate Planning and Business Development. He was appointed Senior Vice President and Chief Financial Officer in January 2009. He is a director of the Canexus Income Fund.

Kevin is a Chartered Accountant and holds a Bachelor of Commerce degree from Saint Mary's University, Halifax.



Laurence Murphy

Executive Vice President, International Oil and Gas

Larry has been with Nexen since 1986 in a variety of positions in the Petrogas Operations, Corporate Planning and International divisions. Larry has been the Senior Vice President, International Oil and Gas since 1999 and was appointed Executive Vice President, International Oil and Gas in 2007.

Larry holds a Bachelor of Science degree in Mechanical Engineering from University College in Ireland.

Roger D. Thomas

Executive Vice President, North America

Since joining Nexen in 1978, Roger has held various positions including Business Manager, Specialty Chemicals Division; Vice President, Oil and Gas Marketing; and Vice President, Corporate Planning. He was appointed Executive Vice President, North America in 2007.

Roger graduated from the University of Toronto and York University, with a Bachelor of Arts degree in Economics/History. He is also a graduate of the Executive Program at the University of Michigan.

Gary H. Nieuwenburg

Senior Vice President, Synthetic Crude

Gary joined Nexen in 1981 and has held various positions of increasing responsibility including Vice President, Exploration and Production, Canadian Oil and Gas; and Vice President, Corporate Planning and Business Development. He was appointed Senior Vice President, Synthetic Crude in 2007.

Gary holds a Mechanical Engineering degree from the University of Manitoba.

Brian C. Reinsborough

Senior Vice President, United States Oil and Gas

Since joining Nexen in 1992, Brian has progressed through the US Oil and Gas division in various roles including Exploration Manager, Deepwater; Vice President, Exploration; and Vice President, Exploration, Operations and Production. In 2007, he was appointed Senior Vice President, US Oil and Gas.

Brian holds a Master of Geology degree from the University of Texas in Austin and a Bachelor of Geology degree from New Brunswick's Mount Allison University.

Tim J. Thomas

Senior Vice President, Canadian Oil and Gas

Tim joined Nexen in 1991 and has held various positions including Vice President, Yemen Operations and International Business Development; President and General Manager, Yemen Operations; General Manager, Business Development (London); and Vice President, Exploration and Production, Canadian Oil and Gas. Tim was appointed Senior Vice President, Canadian Oil and Gas in 2007.

Tim holds a Bachelor of Science degree in Petroleum Engineering from the Imperial College of Science in the UK.

Una M. Power

Vice President,
Corporate Planning and
Business Development

Una joined Nexen in 1992 and has held numerous positions in the Finance area including Treasurer, Manager of Investor Relations and Controller. She was appointed Vice President, Corporate Planning and Business Development in January 2009.

Una holds a Bachelor of Commerce Honours degree from Memorial University in Newfoundland. She is a Chartered Accountant and Chartered Financial Analyst.

Robert J. Black

Vice President,
Energy Marketing

Bob joined Nexen in 1992 as the Manager of Crude Oil Marketing and served as Executive Vice President, North American Marketing for Nexen Marketing. In 2002, Bob was appointed Vice President, Energy Marketing.

Bob holds a Bachelor of Arts in Economics from the University of Calgary.

Randy J. Jahrig

Vice President,
Human Resources and
Corporate Services

Randy joined Nexen in 1990. He has served as a Staff Human Resources Advisor in the Chemicals division; Vice President of Human Resources for the Canadian Oil and Gas division; and in 2005, continued in his role as Vice President, Human Resources, Canada and International.

Randy holds a diploma in Business Administration from NAIT and is a Certified Human Resources Professional.

Kim D. McKenzie

Vice President and
Chief Information Officer

Kim joined Nexen in 1985 as the Manager, Business Systems. He was appointed Vice President, Information Technology in 1992 and subsequently Vice President and Chief Information Officer in November 2007.

Kim graduated from the University of Alberta with a Bachelor of Commerce degree.

Eric B. Miller

Vice President,
General Counsel
and Secretary

Eric joined Nexen in 1993 and has held several senior legal positions within Nexen's domestic and international divisions. He is currently the Vice President, General Counsel and Secretary.

Eric holds a Bachelor of Commerce degree from the University of Calgary, and a Bachelor of Laws and Master of Business Administration degrees from Osgoode Hall Law School and the Schulich School of Business (York) in 1989. In 2007, Eric received the ICD.D designation from the Institute of Corporate Directors.

Brendon T. Muller

Controller

Brendon joined Nexen's corporate accounting group in 2002 and quickly took on increased responsibility in managing the company's external financial reporting to the U.S. and Canadian regulatory bodies. He was appointed Controller in 2007.

Brendon graduated with a Bachelor of Commerce degree from the University of Calgary and is a Chartered Accountant.

J. Michael Backus

Treasurer

Mike joined Nexen in 1997 and has held several positions within the company, including Drilling and Completions Engineer; Reservoir Engineer; Investor Relations Analyst; and Manager of Planning for Synthetic Oil. He was appointed Treasurer in February 2009.

Mike is a Professional Engineer and holds both Bachelor of Commerce and Bachelor of Science degrees from the University of Saskatchewan.

BOARD OF DIRECTORS

	Francis M. Saville, Q.C.	Marvin F. Romanow	Bill B. Berry	Robert G. Bertram	Dennis G. Flanagan	David A. Hentschel	S. Barry Jackson
Residence	Calgary, Alberta, Canada	Calgary, Alberta, Canada	Houston, Texas, United States	Aurora, Ontario, Canada	Calgary, Alberta, Canada	Tulsa, Oklahoma, United States	Calgary, Alberta, Canada
Director Since	1994	2009	2008	2009	2000	1985*	2001
Nexen Shares	48,860	187,432	–	16,000	31,264	70,925	72,000
DSUs	46,117	–	5,000	5,000	35,660	35,656	48,145
Principal Occupation	Chair of Nexen	President and CEO of Nexen	Retired oil and gas executive	Retired pension investment executive	Retired oil and gas executive	Retired oil and gas executive	Retired oil and gas executive

Francis Saville, 70, Chair of Nexen, is counsel with Fraser Milner Casgrain LLP, Barristers and Solicitors. He joined the firm in 1965 and had an extensive practice in the areas of energy and environmental law, as well as municipal law and land-use planning. He specialized in representing energy corporations in regulatory applications.

Marvin Romanow, 53, has been President and Chief Executive Officer of Nexen Inc. since January 1, 2009. He was Executive Vice President and Chief Financial Officer since June 2001. Prior to this, he held a variety of finance positions at Nexen. Marvin is a director of the Canexus Income Fund and the Canadian Energy Research Institute. He is a past board member of Syncrude Canada.

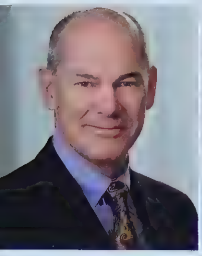
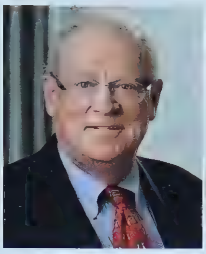
William Berry, 56, is a retired oil and gas executive. He was formerly Executive Vice President of ConocoPhillips from 2003 to 2008. He also held senior executive positions with Phillips Petroleum Co. His career in the oil and gas industry began in 1976 and includes experience working in West Africa, the North Sea, Asia, Russia, Caspian Sea and North America.

Robert Bertram, 64, is the retired Executive Vice President of Ontario Teachers Pension Plan Board (Teachers'), a position he held from 1990 to December 2008. He led Teachers' investment program and had oversight of the pension fund's growth to $108.5 billion from $19 billion when it was established in 1990. Prior to that, he spent 18 years at Telus Corporation, formerly Alberta Government Telephones. Before leaving Telus, he was Assistant Vice President and Treasurer.

Dennis Flanagan, 69, is a retired oil and gas executive. He worked in the oil and gas industry for more than 40 years with Ranger Oil Limited (Ranger) and ELAN Energy Inc. (ELAN), most recently as Executive Chair of ELAN until it was bought by Ranger in 1997. He was involved in all phases of exploration and development in Canada, the US and the UK North Sea.

Dave Hentschel, 75, is the retired Chair and CEO of Occidental Oil and Gas Corporation, the worldwide oil and gas subsidiary of Occidental Petroleum Corporation. He was President and CEO of Nexen from January 1996 until June 1997.

Barry Jackson, 56, is the retired Chair of Resolute Energy Inc. and Deer Creek Energy Limited. He was formerly President, CEO and a director of Crestar Energy Inc. (Crestar). He has worked in the oil and gas industry since 1974 and held senior executive positions with Northstar Energy Corporation and Crestar.

	Kevin J. Jenkins	A. Anne McLellan, P.C.	Eric P. Newell, O.C.	Thomas C. O'Neill	Richard M. Thomson, O.C.	John M. Willson	Victor J. Zaleschuk
Residence	Calgary, Alberta, Canada	Edmonton, Alberta, Canada	Edmonton, Alberta, Canada	Toronto, Ontario, Canada	Toronto, Ontario, Canada	Vancouver, British Columbia, Canada	Calgary, Alberta, Canada
Director Since	1996	2006	2004	2002	1997*	1996	1997
Nexen Shares	12,415	300	12,000	16,000	92,004	15,055	63,152
DSUs	48,789	26,943	57,824	45,618	72,672	48,200	37,430
Principal Occupation	Managing Director of TriWest Capital Partners	Counsel with Bennett Jones LLP, Barristers and Solicitors	Retired Chair and CEO of Syncrude Canada Ltd.	Retired Chair of PwC Consulting	Retired banking executive	Retired mining executive	Retired oil and gas executive

Kevin Jenkins, 52, is a Managing Director of TriWest Capital Partners, an independent private equity firm. He was President, CEO and a director of The Westaim Corporation from 1996 to 2003. From 1985 to 1996, he held senior executive positions with Canadian Airlines International Ltd. (Canadian). He was elected to Canadian's board of directors in 1987, appointed President in 1991 and appointed President and CEO in 1994.

The Honourable Anne McLellan, 58, has been counsel at Bennett Jones LLP, Barristers and Solicitors and Distinguished Scholar in Residence at the University of Alberta in the Institute for US Policy Studies since 2006. Previously, she served as the Liberal Member of Parliament for Edmonton Centre from 1993 to 2006. Between 2003 and 2006, she served as the Deputy Prime Minister and Minister of Public Safety and Emergency Preparedness.

Eric Newell, 64, is the retired Chancellor of the University of Alberta, a position he held from 2004 to 2008. He is also the retired Chair and CEO of Syncrude Canada Ltd. (Syncrude), positions he held from 1994 and 1989, respectively, until January 2004. He served as President of Syncrude from 1989 to 1997. Prior to that, he worked with Imperial Oil Limited and Esso Petroleum Canada Ltd.

Tom O'Neill, 63, is the retired Chair of PwC Consulting. He was formerly CEO of PwC Consulting, COO of Pricewaterhouse-Coopers LLP, Global, CEO of Pricewaterhouse-Coopers LLP, Canada, and Chair and CEO of Price Waterhouse Canada. He worked in Brussels in 1975 to broaden his international experience and from 1975 to 1985 was client service partner for numerous multinationals, specializing in dual Canadian and US-listed companies.

Dick Thomson, 75, is a retired banking executive. He was with the Toronto-Dominion Bank, one of Canada's largest banks, since 1957, as Chair from 1978 until his retirement in 1998 and as President from 1972 to 1978.

John Willson, 69, is the retired President and CEO of Placer Dome Inc., a position he held from 1993 to 1999. He was President and CEO of Pegasus Gold Inc. from 1989 to 1992 and was with Cominco Limited prior to that. During his career, he worked in Ghana, Montana, Washington State, British Columbia, the Northwest Territories and Greenland.

Vic Zaleschuk, 65, is the retired President and CEO of Nexen, a position he held from 1997 to 2001. He joined Nexen in 1986, as the company was developing operations in Yemen and expanding its international strategy. From 1986 to 1994, he was Senior Vice President, Finance and from 1994 to 1997, he was Senior Vice President and CFO.

** Retiring April 2009*

CORPORATE INFORMATION

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801 – 7th Avenue SW
Calgary, Alberta, Canada T2P 3P7
T 403.699.4000
F 403.699.5800
www.nexeninc.com

INVESTOR RELATIONS CONTACT
Michael J. Harris
Vice President, Investor Relations
T 403.699.4688
F 403.699.5730
mike_harris@nexeninc.com

ANNUAL GENERAL MEETING
10:00 a.m. M.T.
Tuesday, April 28, 2009
The Fairmont Palliser Hotel
133 – 9th Avenue SW
Calgary, Alberta, Canada

STOCK SYMBOL—NXY
Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

PREFERRED SECURITIES
7.35% Subordinated Notes
TSX—NXY.PR.U
NYSE—NXYPRB

COMMON SHARE TRANSFER AGENT AND REGISTRARS
CIBC Mellon Trust Company
Calgary, Toronto, Montreal and Vancouver, Canada
BNY Mellon Shareowner Services
Jersey City, New Jersey, US

DIVIDEND REINVESTMENT PLAN
The offering circular (and for US residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or at www.cibcmellon.com

AUDITORS
Deloitte & Touche LLP
Calgary, Alberta, Canada

CONVERSIONS
Natural gas is converted at 6 mcf per equivalent barrel of oil.

DOLLAR AMOUNTS
In Canadian dollars unless otherwise stated.

OPERATING ENTITIES

Canada
Nexen Crossfield Partnership
Nexen Med Hat-Hatton Partnership
Nexen Oil Sands Partnership

United States
Nexen Petroleum Offshore U.S.A. Inc.
Nexen Petroleum U.S.A. Inc.

International
Canadian Nexen Petroleum East Al Hajr Ltd.
Canadian Nexen Petroleum Yemen
Nexen Ettrick U.K. Limited
Nexen Exploration Norge AS
Nexen Exploration U.K. Limited
Nexen Petroleum Colombia Limited
Nexen Petroleum Deepwater Nigeria Limited
Nexen Petroleum Exploration and Production Nigeria Limited
Nexen Petroleum Nigeria Limited
Nexen Petroleum U.K. Limited

Marketing
Nexen Energy Marketing Europe Limited
Nexen Energy Marketing London Limited
Nexen Marketing
Nexen Marketing Singapore Pte. Ltd.
Nexen Marketing U.S.A. Inc.

Chemicals
Canexus Chemicals Canada Limited Partnership
Canexus U.S. Inc.
Canexus Química Brasil Ltda.

OFFICERS

Francis M. Saville, Q.C.
Chair of the Board

Marvin F. Romanow
President
and Chief Executive Officer

Kevin J. Reinhart
Senior Vice President
and Chief Financial Officer

Laurence Murphy
Executive Vice President,
International Oil and Gas

Roger D. Thomas
Executive Vice President,
North America

Gary H. Nieuwenburg
Senior Vice President,
Synthetic Crude

Brian C. Reinsborough
Senior Vice President,
United States Oil and Gas

Tim J. Thomas
Senior Vice President,
Canadian Oil and Gas

Una M. Power
Vice President,
Corporate Planning
and Business Development

Randy J. Jahrig
Vice President,
Human Resources
and Corporate Services

Kim D. McKenzie
Vice President
and Chief Information Officer

Eric B. Miller
Vice President,
General Counsel and Secretary

Brendon T. Muller
Controller

J. Michael Backus
Treasurer

Rick C. Beingessner
Assistant Secretary

Sylvia L. Groves
Assistant Secretary

For more information on our officers and directors, please see Item 10 in our Form 10-K.

FORWARD-LOOKING STATEMENTS

Certain statements in this report constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil, natural gas or chemicals prices, future production levels, future cost recovery oil revenues from our Yemen operations, future capital expenditures and their allocation to exploration and development activities, future earnings, future asset dispositions, future sources of funding for our capital program, future debt levels, availability of committed credit facilities, possible commerciality, development plans or capacity expansions, future ability to execute dispositions of assets or businesses, future cash flows and their uses, future drilling of new wells, ultimate recoverability of current and long-term assets, ultimate recoverability of reserves or resources, expected finding and development costs, expected operating costs, future demand for chemicals products, estimates on a per share basis, sales, future expenditures and future allowances relating to environmental matters and dates by which certain areas will be developed or will come on stream, and changes in any of the foregoing are forward-looking statements. Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas and chemicals products; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; volatility in energy trading markets; foreign-currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; and political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement. Readers should also refer to Items 1A and 7A in our 2008 Annual Report on Form 10-K for further discussion of the risk factors.

Cautionary Note to US Investors The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to discuss only proved reserves that are supported by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this disclosure, we may refer to "recoverable reserves", "probable reserves", "recoverable resources" and "recoverable contingent resources" which are inherently more uncertain than proved reserves. These terms are not used in our filings with the SEC. Our reserves and related performance measures represent our working interest before royalties, unless otherwise indicated. Please refer to our Annual Report on Form 10-K available from us or the SEC for further reserve disclosure.

In addition, under SEC regulations, the Syncrude oil sands operations are considered mining activities rather than oil and gas activities. Production, reserves and related measures in this report include results from the Company's share of Syncrude.

Under SEC regulations, we are required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil we will produce and sell from Long Lake.

Cautionary Note to Canadian Investors Nexen is required to disclose oil and gas activities under *National Instrument 51-101–Standards of Disclosure for Oil and Gas Activities* (NI 51-101). However, the Canadian securities regulatory authorities (CSA) have granted us exemptions from certain provisions of NI 51-101 to permit US style disclosure. These exemptions were sought because we are a US Securities and Exchange Commission (SEC) registrant and our securities regulatory disclosures, including Form 10-K and other related forms, must comply with SEC requirements. Our disclosures may differ from those of Canadian companies who have not received similar exemptions under NI 51-101.

Please read the "Special Note to Canadian Investors" in Item 7A in our 2008 Annual Report on Form 10-K, for a summary of the exemption granted by the CSA and the major differences between SEC requirements and NI 51-101. The summary is not intended to be all-inclusive or to convey specific advice. Reserve estimation is highly technical and requires professional collaboration and judgment.

Because reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.

Please note that the differences between SEC requirements and NI 51-101 may be material.

Our probable reserves disclosure applies the Society of Petroleum Engineers/World Petroleum Council (SPE/WPC) definition for probable reserves. *The Canadian Oil and Gas Evaluation Handbook* states there should not be a significant difference in estimated probable reserve quantities using the SPE/WPC definition versus NI 51-101.

In this disclosure, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

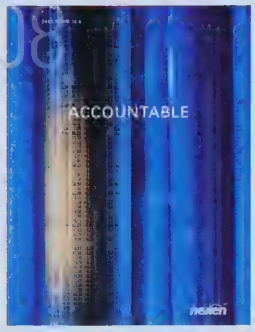
Resources Nexen's estimates of contingent resources are based on definitions set out in *The Canadian Oil and Gas Evaluation Handbook* which generally describes contingent resources as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Such contingencies may include, but are not limited to, factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. Specific contingencies precluding these contingent resources being classified as reserves include but are not limited to: future drilling program results, drilling and completions optimization, stakeholder and regulatory approval of future drilling and infrastructure plans, access to required infrastructure, economic fiscal terms, a lower level of delineation, the absence of regulatory approvals, detailed design estimates and near-term development plans, and general uncertainties associated with this early stage of evaluation. The estimated range of contingent resources reflects conservative and optimistic likelihoods of recovery. However, there is no certainty that it will be commercially viable to produce any portion of these contingent resources.

Nexen's estimates of discovered resources (equivalent to discovered petroleum initially-in-place) are based on definitions set out in *The Canadian Oil and Gas Evaluation Handbook* which generally describes discovered resources as those quantities of petroleum estimated, as of a given date, to be contained in known accumulations prior to production. Discovered resources do not represent recoverable volumes. We disclose additional information regarding resource estimates in accordance with NI 51-101. These disclosures can be found on our website and on SEDAR. Additional disclosure of our Horn River shale gas resource can be found in our press release dated April 22, 2008.

Cautionary statement In the case of discovered resources or a subcategory of discovered resources other than reserves, there is no certainty that it will be commercially viable to produce any portion of the resources. In the case of undiscovered resources or a subcategory of undiscovered resources, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

ANNUAL PUBLICATIONS

The following reports are available on our website at **www.nexeninc.com/investors** and hard copies may be ordered online or by calling **403.699.4354.**



2008 Form 10-K

2008 Sustainability Report (available June 2009)

2009 Management Proxy Circular

2008 Statistical Supplement

2008 AWARDS AND RECOGNITION

Global 100 list
from *Corporate Knights Magazine* and Innovest for most sustainable international corporations

Best Corporate Governance Practices in North America
IR Global Rankings

Report on Business Corporate Governance
ranked 7th scoring 92 out of 100

GovernanceMetrics International
10 out of 10 for governance disclosure

Canada's 30 Best Pension and Benefits Plans
from *Benefits Canada* magazine and Hewitt Associates

Environmental Leadership Award
from Fort McMurray Chamber of Commerce for Long Lake Project

Corporate Reporting Award of Excellence
from Canadian Institute of Chartered Accountants (CICA) for top financial, governance and sustainability disclosures in oil and gas

Corporate Reporting Award of Excellence
from the CICA for top governance disclosure across all sectors

Oilweek Annual Report Awards
from *Oilweek Magazine*/ATB Financial for best editorial/graphic design in senior oil and gas

Best Sustainability Report Award
from *Oilweek Magazine*/ATB Financial for top Sustainability Report overall

World Petroleum Congress President for 3rd term
Randy Gossen—Nexen's VP, Global Business Relations

Top 100 Best Companies to Work For
from *The Sunday Times* (UK) Nexen UK division ranked 30th

Eric L. Harvie—Glenbow Award
for continued sponsorship of Glenbow Museum's education programs

Canadian Event Industry Awards
for 'Feel the Beat' employee event

Healthy Living Award
from Government of Scotland for healthy menus on Scott platform

Design: Karo Group Printed in Canada by Rhino Print Solutions

We'll continue making choices that
open doors to tomorrow's value.

2008 FORM 10-K

ACCOUNTABLE

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2008

Commission File Number 1-6702

NEXEN INC.

Incorporated under the Laws of Canada

nexen

98-6000202

(I.R.S. Employer Identification No.)

801 – 7th Avenue S.W.

Calgary, Alberta, Canada T2P 3P7

Telephone: (403) 699-4000

Web site: www.nexeninc.com

Securities registered pursuant to Section 12(b) of the Act:

Title	Exchange Registered On
Common shares, no par value	The New York Stock Exchange The Toronto Stock Exchange
Subordinated Securities, due 2043	The New York Stock Exchange The Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes _√_ No ___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ___ No _√_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes _√_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _√_

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer _√_ Accelerated filer ___ Non-accelerated filer ___ Smaller reporting company ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No _√_

On June 30, 2008, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $22 billion based on the Toronto Stock Exchange closing price on that date. On January 30, 2009, there were 519,820,961 common shares issued and outstanding.

TABLE OF CONTENTS

Special Note to Canadian Investors—see page 79

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format. Volumes and reserves include Syncrude operations unless otherwise stated.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

/d	=	per day	mboe	=	thousand barrels of oil equivalent
bbl	=	barrel	mmboe	=	million barrels of oil equivalent
mbbls	=	thousand barrels	mcf	=	thousand cubic feet
mmbbls	=	million barrels	mmcf	=	million cubic feet
mmbtu	=	million British thermal units	bcf	=	billion cubic feet
km	=	kilometre	WTI	=	West Texas Intermediate
MW	=	megawatt	NGL	=	natural gas liquid
PSC™	=	premium synthetic crude	NYMEX	=	New York Mercantile Exchange

In this 10-K, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf/1bbl). This conversion may be misleading, particularly if used in isolation, as the 6mcf/1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

The noon-day Canadian to US dollar exchange rates for Cdn $1.00, as reported by the Bank of Canada, were:

(US$)	December 31	Average	High	Low
2004	0.8308	0.7683	0.8493	0.7159
2005	0.8577	0.8253	0.8690	0.7872
2006	0.8581	0.8818	0.9099	0.8528
2007	1.0120	0.9304	1.0905	0.8437
2008	0.8166	0.9381	1.0289	0.7711

On January 30, 2009, the noon-day exchange rate was US $0.8088 for Cdn $1.00.

Electronic copies of our filings with the Securities Exchange Commission (SEC) and the Ontario Securities Commission (OSC) (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, on request, by contacting our investor relations department at 403.699.5931. As soon as reasonably practicable, our filings are made available on our website once they are electronically filed with the SEC and/or the OSC. Alternatively, the SEC and the OSC each maintain a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the OSC. The information on our website, is not, and shall not be deemed to be, a part of this Annual Report on Form 10-K.

OPERATIONS

In 2008, Buzzard delivered exceptional value. Long Lake produced first premium synthetic crude in January 2009.

ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 as Canadian Occidental Petroleum Ltd. when Occidental Petroleum Corporation (Occidental) combined their Canadian crude oil, natural gas, sulphur and chemical operations into one company. We've grown from producing 10,700 boe/d before royalties with revenues of $26 million in 1971, to producing over 250,000 boe/d before royalties (including Syncrude production) and revenues of $8.2 billion in 2008. We achieved this growth through exploration success and strategic acquisitions. Operating for more than 35 years, we have been profitable every year, except one, and have been paying quarterly dividends consecutively since 1975.

Where we came from

1970s	• broadened our western Canadian asset base and entered the US Gulf of Mexico • finished the decade with production of about 11,000 boe/d and revenues of $126 million
1980s	• grew our western Canadian and Gulf of Mexico assets through acquisitions • acquired Canada-Cities Service doubling our size and captured an interest in Syncrude • finished the decade with production of about 69,000 boe/d and revenues of $591 million
1990s	• discovered the first of 17 fields at Masila in Yemen in 1990 and production commenced in 1993 • tripled our Canadian production in 1997 by purchasing Wascana Energy Inc. • explored and made several discoveries, such as our 1998 Ukot discovery on block OPL-222, offshore Nigeria • finished the decade with production of about 239,000 boe/d and revenues of $1.7 billion

Who we are now

2000–2008	• made several significant international discoveries including: Gunnison, Aspen, Knotty Head and Longhorn in the deep-water Gulf of Mexico; Guando in Colombia; Block 51 in Yemen; and Usan, offshore Nigeria • acquired properties in the UK North Sea in 2004, including operatorship of the Buzzard discovery, the producing Scott and Telford fields and 700,000 exploration acres. Buzzard came on stream in 2007 on time and on budget. Made several discoveries including Golden Eagle, Pink and Rochelle • signed a 50/50 joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake utilizing our patented OrCrude™ technology, in the Athabasca oil sands. Construction of the Long Lake Project was completed in 2008 • acquired Occidental's remaining 29% interest in us with Ontario Teachers' Pension Plan Board (Teachers). Teachers purchased 20.2 million common shares and we repurchased the remaining 20 million common shares for $605 million. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations • divested non-core assets in 2005 by selling Canadian properties producing about 18,300 boe/d before royalties and by monetizing 39% of our chemical business through the initial public offering of Canexus Income Fund • developed our first coalbed methane (CBM) project in the Fort Assiniboine area in western Canada in 2005 • captured a significant shale gas position in the Horn River Basin in northeastern BC

Where we are going

2009	• began producing premium synthetic crude in January 2009 at Long Lake. Increased our interest in the Long Lake Project and joint venture lands by 15% and become the sole operator of both the resource and upgrader • continue to enhance and develop production at Long Lake and move towards first production at Ettrick in the UK North Sea and Longhorn in the US Gulf of Mexico later this year • focusing on oil sands, unconventional gas and select conventional exploration and exploitation properties in our core areas • continue to evaluate and appraise potentially significant recent discoveries in the UK North Sea

STRATEGY

Choice—it's what companies and investors value most in challenging times. Whether it's how we allocate capital, fund our growth, or which projects make the most sense in current economic times, choice is key. Our strategy is to build a sustainable energy company focused in three areas: oil sands, unconventional gas and select conventional exploration and exploitation.

To be sustainable we must be better than average. So we operate where we see the greatest opportunity for long-term value creation. Then we invest in solid land positions, developing expertise and applying technology that give us a competitive advantage.

Our goal is to grow long-term value for our shareholders responsibly. Key drivers to growing value include increasing reserves, production, cash flow and net income on a cost-effective basis over the long term. We leverage off our competitive advantages to generate opportunities for long-term success in our evolving industry.

As conventional basins in North America mature, we've developed specific capabilities in oil sands, CBM, deep-water technology and international experience. These skills enable us to focus on specific types of projects, as we transition toward major projects in established basins, exploration in less mature basins and exploitation of unconventional resources.

Today, we are building sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:

- diversification—our assets are geographically diverse and we produce oil and gas, onshore and offshore. We have large conventional and unconventional legacy assets in our portfolio;
- significant captured resource—we have key resource plays with a low cost of entry. Our Long Lake Project is developing only 10% of our oil sands leases in the Athabasca oil sands, we hold 195 net sections in the emerging Horn River shale gas play in northeast British Columbia and we hold unexplored acreage in the Gulf of Mexico, the North Sea, western Canada and elsewhere;
- focus on growth—we are growing our business through exploration and innovative technology. We are successful explorers with significant undeveloped discoveries at Knotty Head and Vicksburg in the Gulf of Mexico, the Golden Eagle area in the UK North Sea and at Usan, offshore Nigeria. Long Lake is the first oil sands project to use gasification technology to significantly reduce the cost of producing bitumen and we are advancing new techniques for unconventional production of CBM and enhanced heavy oil recovery in western Canada;
- international expertise—we are an international operator with a proven track record of successful business ventures in Yemen, the United Kingdom, Nigeria, Colombia and Australia;
- strong financial position—we have access to $3.5 billion of liquidity (after acquiring the additional 15% interest in Long Lake in January 2009) through cash and undrawn committed credit facilities to allow us to proceed with investments at the pace of our choice and to take advantage of opportunities as they arise like we did with our strategic entry into the UK North Sea in 2004 and our recent acquisition of an additional 15% working interest at Long Lake; and
- sustainable business practices—leveraging our strength in business practices such as Health, Safety, Environment and Social Responsibility (HSE&SR) to access opportunities and responsibly create and demonstrate both long-term benefits and value growth for our investors, for the communities in which we operate and for other stakeholders. This makes us a desired business partner and/or joint venture operator.

The location and scale of our operations often result in: 1) an extended period of time from the capture of opportunities to first production and 2) non-linear, year-over-year growth in reserves and production. Significant up-front capital investment is often required prior to realizing production and free cash flows. We fund this investment by maximizing cash flow from our producing assets, issuing long-term debt and/or equity and selling non-core assets into attractive markets.

Our financial position is strong. We have financial flexibility with major capital projects complete at Buzzard and Long Lake, and industry-leading cash netbacks. We have available liquidity of approximately $3.5 billion (after acquiring the additional 15% interest in Long Lake), split between cash and undrawn committed credit. We have no debt maturities until 2011 and our average term-to-maturity of our long-term debt is approximately 18 years.

In creating sustainable businesses, we are committed to good corporate governance practices and social responsibility. We believe that over the long term, companies that follow sustainable business practices outperform those with narrower priorities. We foster dialogue with stakeholders about our operational opportunities and challenges, from exploration to development to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing multiple, and sometimes conflicting goals.

For financial reporting purposes, we report on four main segments:

- oil and gas;
- Syncrude;
- energy marketing; and
- chemicals.

Our oil and gas operations are broken down geographically into the UK North Sea, US Gulf of Mexico, Canada, Yemen and Other International (currently Colombia, offshore West Africa and Norway). Results from our Long Lake Project are included in Canada. Syncrude is our 7.23% interest in the Syncrude Joint Venture. Energy marketing includes our crude oil, natural gas, natural gas liquids and power marketing businesses in North America, Europe and Asia. Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda, muriatic acid and chlorine through Canexus Limited Partnership.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 22 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

UNDERSTANDING THE OIL AND GAS BUSINESS

The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price that products command in the market based on quality and marketing efforts. Our goal is to extract the maximum value from each barrel of oil equivalent, so every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash flow generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices. We maintain liquidity that provides us with the ability to invest in high-quality projects that we believe will generate value over the long term.

The prices we receive for our oil and gas products are determined by global crude oil and natural gas markets, which can be volatile, and by worldwide supply/demand fundamentals. With many alternative customers, the loss of any one customer is not expected to have a significantly adverse effect on the price of

our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products can fluctuate season to season, which impacts price. In particular, heavy oil is typically in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating. We manage our operations on a country-by-country basis, reflecting differences in the regulatory and competitive environments and risk factors associated with each country.

OIL AND GAS OPERATIONS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, western Canada, Yemen, Colombia, offshore West Africa and Norway. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

In this Form 10-K, we provide estimates of remaining quantities of proved oil and gas reserves for our various properties. Such estimates are internally prepared. Additionally, at the end of the year, 98% of our oil and gas reserves before royalties (98% after royalties) and 100% of our Syncrude reserves before royalties (100% after royalties) were assessed (either evaluated or audited as described on page 19) by independent reserves consultants. Their assessments are performed at varying levels of property aggregation, and we work with them to reconcile the differences on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively; however, we believe such differences are not material relative to our total proved reserves. Refer to the section on Critical Accounting Estimates—Oil and Gas Accounting—Reserves Determination on page 70 for a description of our reserves process, and to the section on Reserves, Production and Related Information on page 15 for a description of the nature and scope of the independent assessments performed and the results thereof.

Certain statements in these items 1 and 2 constitute "forward-looking statements" and the reader should refer to the "Special Note Regarding Forward-Looking Statements" set out on page 78 of this 10-K.

North Sea—United Kingdom (UK)

The UK North Sea is a key producing area. Our assets include a 43.2% operated interest in the Buzzard field and facilities, a 41.9% operated interest in the Scott field and production platform, a 71.8% operated interest in the Telford field, interests in several satellite discoveries and more than 750,000 net undeveloped exploration acres. We are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. Our North Sea properties have high-margin reserves and production, diversify our global portfolio by adding strong assets in a stable jurisdiction, and complement our other longer cycle-time projects.

Our UK strategy is to grow and sustain our existing North Sea production and identify new production hubs with exploration and exploitation opportunities near existing infrastructure. We have a number of exploitation opportunities in our existing fields and smaller undeveloped discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford, Buzzard or Ettrick. As a result, new discoveries can be tied-in quickly.

During the year, we produced 102,700 boe/d before royalties (102,700 after royalties) in the UK, which was approximately 41% of our total production. At year end, our UK proved oil and gas reserves of 175 mmboe before royalties (175 after royalties) represented about 18% of our total proved oil and gas and Syncrude reserves before royalties (19% after royalties).

Buzzard

Buzzard is the largest discovery in the UK North Sea in over a decade. It was discovered in 2001 and construction of the platforms and facilities was completed in 2006. Production came on stream early 2007 and the project was completed on time and on budget.

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. The Buzzard development includes three platforms that can process at least 200,000 bbls/d of oil and 60 mmcf/d of gas. We have drilled 18 development wells and 14 of them are on stream. Development drilling resulted in more well-to-well variability in the concentration of hydrogen sulphide than originally expected. To address this, we are constructing a fourth platform with production sweetening facilities to handle higher levels of hydrogen sulphide. Existing equipment and

processes can manage current hydrogen sulphide levels and maintain current production deliverability until the additional equipment is commissioned, which is scheduled for 2010.

Oil from Buzzard is exported via the Forties pipeline to the Grangemouth refinery in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

We expect to produce the Buzzard field through 27 production wells and maintain reservoir pressure with an active water-flood program. During 2008, the Buzzard field reached a milestone when it exported 100 million barrels of crude oil. In 2009, we plan to drill four production wells, two water injectors and progress work on the fourth platform. During the third quarter of 2009, we plan to install the jackets for this platform and complete tie-in operations, pending installation of the topsides. This will result in about one month of downtime which coincides with a six week planned slowdown of the Forties pipeline.

Scott/Telford

Scott and Telford are producing fields with additional exploitation opportunities and both tie back to the Scott platform. Scott was discovered in 1987 and began producing in September 1993, while Telford was discovered in 1991 and came on stream in 1996. We have a 41.9% working interest in the Scott platform and field, and a 71.8% working interest in Telford. In 2008, our share of production from these fields was approximately 10,500 boe/d. The production is around 90% oil and produced through subsea wells tied back to the Scott platform. Oil is delivered to the Grangemouth refinery in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in northeast Scotland. In recent years, the Scott platform underwent a significant maintenance turnaround and facilities upgrade to improve reliability and extend facility life.

Ettrick

We are progressing development of the Ettrick field and first oil is expected in the next few months. The FPSO is currently being commissioned and expected to be on location shortly. Development of the field includes five subsea production wells and three water injectors tied back to a leased FPSO; however, we are developing Ettrick as a new production hub and we expect to tie-in new discoveries. We are reviewing our recent exploration success at Blackbird as a potential tie-back to the Ettrick FPSO. The FPSO is designed to handle 30,000 bbls/d of oil, 35 mmcf/d of gas and to re-inject 55,000 bbls/d of water. We operate Ettrick with an 80% working interest.

Other

We have interests in two smaller non-operated fields in the UK North Sea. The Farragon field was brought on stream in late 2005. In 2007, the Duart field began producing oil from a single well tied back to the Tartan platform. Our share of production in 2008 from these properties was 3,900 boe/d before royalties (3,900 after royalties).

Exploration and Undeveloped Assets

We continue to actively explore in the UK North Sea and hold several undeveloped discoveries on operated blocks near Scott, Buzzard and Ettrick as follows:

Field	Interest (%)	Operator Status	Comments
Blackbird	80	operated	discovery near Ettrick; appraisal well planned for 2009
Black Horse	50	operated	discovery near Scott; evaluating development alternatives
Bugle	41	operated	discovery near Scott; evaluating development alternatives
Ferret (Polecat)	40	operated	discovery near Buzzard; appraisal well planned for 2009
Golden Eagle	34	operated	discovery near Buzzard; evaluating development alternatives
Hobby	34	operated	discovery near Buzzard; successful well drilled January 2009
Kildare	50	operated	discovery near Scott; evaluating development alternatives
Perth	42	operated	discovery near Scott; evaluating development alternatives
Pink	46	operated	discovery near Golden Eagle; appraisal well planned for 2009
Rochelle	44	non-operated	discovery near Scott; successful well drilled January 2009

In 2007, we discovered hydrocarbons at Golden Eagle, which was further appraised with a sidetrack well. We are currently evaluating development options and expect to sanction development in 2009. In 2008, we drilled two exploration wells in the UK North Sea that found hydrocarbons at Blackbird and Pink. In early 2009, we discovered hydrocarbons at Rochelle and Hobby.

In 2009, we plan to drill four exploration wells and four appraisal wells. We may modify our current 2009 drilling plans depending on various factors, including our partners' financial situation, the current global economic environment and declining commodity prices.

We are also assessing emerging CBM opportunities onshore in the UK. In 2006, we acquired an 80% working interest in one opportunity and subsequently drilled two successful exploration wells. Both wells encountered coal seams and are being monitored through ongoing production testing.

Fiscal Terms

In the UK, new discoveries pay no royalties and result in cash netbacks that are higher than our company average. Scott is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which isn't expected before 2010. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance. PRT is applicable to fields receiving development consent prior to March 1993. Buzzard, Ettrick, Farragon, Duart and Telford are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate on oil and gas activities is 30% of taxable income and is also subject to a 20% supplemental charge.

Gulf of Mexico—United States (US)

The Gulf of Mexico is an integral part of our growth strategy. Large discoveries, relatively high success rates, expanding production infrastructure and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. While costs of deep-water exploration are high relative to other basins, deep-water prospects generally have multiple sands and high production rates—factors which improve economics. Technology to find, drill, and develop deep-water discoveries is rapidly progressing and becoming more cost effective. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time.

Our strategy in the Gulf is to explore for new reserves, exploit our existing asset base and acquire assets with upside potential. We focus our exploration program on three strategic play types:

- deep-water prospects near existing infrastructure;
- deep-water, Miocene and Lower Tertiary sub-salt plays with the potential to become new core areas; and
- deep-water, Norphlet targets in the eastern Gulf of Mexico.

These plays are relatively under-explored, hold potential for large discoveries and have attractive fiscal terms. The shorter cycle-times for deep-water prospects near infrastructure complement the longer cycle-times for deep-water sub-salt and Norphlet plays. Although competition in the Gulf is strong, we have built a large inventory of deep-water acreage and are now a significant leaseholder in the deep-water.

In 2009, we plan to further our growth strategies. This includes tieing in our four-well subsea tie-back at Longhorn and completing development of Mississippi Canyon 72, both of which are expected on stream in 2009. We also plan to continue to advance our exploration strategy with additional exploratory drilling and seismic evaluation.

US Production

(mboe/d)	2008 Before Royalties	2008 After Royalties	2007 Before Royalties	2007 After Royalties	2006 Before Royalties	2006 After Royalties
Deep Water	12.2	10.7	19.4	17.4	19.6	17.5
Shelf	10.1	8.4	13.8	11.5	15.9	13.2
Total	**22.3**	**19.1**	**33.2**	**28.9**	**35.5**	**30.7**

At year end, proved reserves of 49 mmboe before royalties (43 after royalties) in the Gulf of Mexico represented about 5% of our total proved oil and gas and Syncrude reserves. Our Gulf production and reserves are primarily concentrated in four deep-water and five shallow-water (shelf) areas.

Deep Water

Most of our deep-water production comes from our 30% non-operated Gunnison field and our 100% operated Aspen field. The remainder comes from our 50% non-operated Wrigley field and three 100% operated properties acquired in 2007. In 2009, our 25% non-operated Longhorn field is expected to come on stream and contribute to our Gulf of Mexico production volumes.

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in December 2003 through our truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas. Our Gunnison SPAR facility has excess capacity, leaving room for growth from regional exploration and processing of third-party volumes. We achieved payout on Gunnison in December 2005, just two years after first production. In 2008, our share of production before royalties was approximately 4,200 boe/d (3,700 after royalties).

Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the Shell-operated Bullwinkle platform 16 miles away and began producing in December 2002. Our share of 2008 production before royalties was approximately 3,100 boe/d (2,800 after royalties).

Wrigley is on Mississippi Canyon Block 506 in 3,300 feet of water. The project consists of a single subsea well tied back to the Shell-operated Cognac platform 17 miles away. Wrigley began gas production in July 2007 and our share before royalties in 2008 was approximately 2,400 boe/d (2,100 after royalties).

In 2007, we acquired three new deep-water producing fields: 1) Garden Banks Block 205; 2) Green Canyon 137; and 3) Green Canyon 6/50. These fields are in water depths between 700 and 1,100 feet. Production from Green Canyon 6/50/137 has been temporarily suspended as the third-party platform that processed our oil and gas was destroyed by Hurricane Ike in September 2008. We are currently assessing our options to restore field production.

In 2009, we expect to have two fields begin producing oil and gas. Our non-operated Mississippi Canyon 72 property is designed to come on stream through a single subsea gas well tied back to the BP-operated Pompano Platform five miles northwest of the field. The Longhorn property is on Mississippi Canyon Block 502 in 2,400 feet of water. The project is a non-operated three-well subsea tie-back to the Corral platform located 19 miles north of the field. We expect production from these properties to commence in mid 2009.

Shelf

Our shelf producing assets are offshore Louisiana, primarily in five 100%-owned field areas: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 320/321/339/340, and Vermilion 76 (consisting of Blocks 65, 66 and 67). We continue to look for opportunities to optimize these assets. In 2009, our shelf development program includes a well at Vermilion 76 to access additional reserves and four recompletion projects.

Exploration and Undeveloped Assets

Our undeveloped deep-water discoveries include:

Well	Interest (%)	Operator Status	Comments
Tobago	10	non-operated	sanctioned; production expected 2010
Knotty Head	25	operated	discovery; further appraisal required
Vicksburg	25	non-operated	discovery; further appraisal required

During the year, we drilled two exploratory dry holes in deep water and acquired additional deep-water acreage. We hold approximately 236 blocks and expect this acreage and future exploration opportunities to position us well for continued growth. In 2009, our expected exploration program includes one exploration well and two appraisal wells, all in deep water. To explore our land inventory and evaluate existing discoveries, we secured two new-build dynamically-positioned fifth-generation semi-submersible drilling rigs. We share access to the rigs that provides us with the ability to use each rig for a total of 24 months over the next four years. We expect the first rig will become available late 2009, followed by the second rig in 2010.

Fiscal Terms

In 2008, royalty rates on our US production averaged 16.5% for shelf volumes and 12.2% for deep-water volumes. The US government increased royalty rates from 12.5% to 16.7% for new deep-water leases awarded after July 2007. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmboe of production. The US Department of the Interior's Minerals Management Service (MMS) suspended royalty relief on our Gunnison lease and assessed royalties on our production from the field. The oil and gas industry litigated the enforceability of these actions and won a judgement in a US District Court. The MMS subsequently lost their appeal of that judgement in January 2009. Our Aspen field is not subject to a minimum price threshold. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0% to 12%.

Canada

Our strategy in Canada is two fold: 1) develop unconventional resource opportunities (oil sands, CBM and shale gas) and 2) maximize value from our established operations through disciplined or selective conventional development and enhanced recovery methods. In 2008, we produced 41,900 boe/d before royalties (34,300 after royalties) in Canada, which was approximately 17% of our total production including Syncrude. At year end 2008, Canadian proved reserves (including bitumen and excluding Syncrude) of 375 mmboe before royalties (362 after royalties) were approximately 38% before royalties (39% after royalties) of our total proved oil and gas and Syncrude reserves.

Our Canadian conventional assets include heavy oil production in east-central Alberta and west-central Saskatchewan, and natural gas near Calgary and in southern Alberta and Saskatchewan. We operate most of our producing properties and hold almost one million net acres of undeveloped land across western Canada. These assets provide predictable production volumes and earnings while we advance the following initiatives for future growth:

- Athabasca oil sands—to produce and upgrade bitumen into synthetic crude;
- shale gas—to evaluate natural gas from organic shales;
- coalbed methane (CBM)—to extract natural gas primarily from Upper Mannville and Horseshoe Canyon coals; and
- enhanced oil recovery (EOR)—to increase recovery in our heavy oil fields.

In 2008, we invested $1,427 million in Canada including $1,320 million into these growth initiatives. With the completion of Long Lake Phase 1 in the Athabasca oil sands, we plan to reduce our capital expenditures in 2009 in Canada. Our 2009 capital programs are focused on optimizing and sustaining Long Lake, evaluating and progressing our shale gas opportunities and advancing our CBM strategies.

Athabasca Oil Sands

The Athabasca oil sands in northeast Alberta is a key growth area for Nexen. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our Long Lake Project involves integrating steam-assisted-gravity-drainage (SAGD) bitumen production with field upgrading technology to produce a premium synthetic crude for sale, and a synthetic gas, which significantly reduces our need to purchase natural gas for operations. We also have a 7.23% investment in the Syncrude oil sands mining operation.

Long Lake Project

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake lease using SAGD for bitumen production and proprietary OrCrude™ technology for our first stage of upgrading. OPTI has the exclusive Canadian license for the OrCrude™ technology. We acquired the exclusive right to use this technology with OPTI within approximately 100 miles of Long Lake, and the right to use the technology independently elsewhere in the world.

SAGD bitumen operations started in mid 2008 and we began producing premium synthetic crude from the upgrader in January 2009. Early in 2009, we acquired an additional 15% interest in the Long Lake Project and the joint venture lands from OPTI, increasing our ownership level to 65%. Following this acquisition, we are now responsible for operating both the SAGD bitumen extraction process and the upgrader for Phase 1 as well as for future phases.

SAGD and Upgrader Integration

SAGD involves drilling two parallel horizontal wells, generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude is upgraded to light (39° API) premium synthetic sweet crude oil, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel for generating steam and as a source of hydrogen for the hydrocracking process. The gas is also burned in a cogeneration plant to produce electricity for on-site use and sold to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is

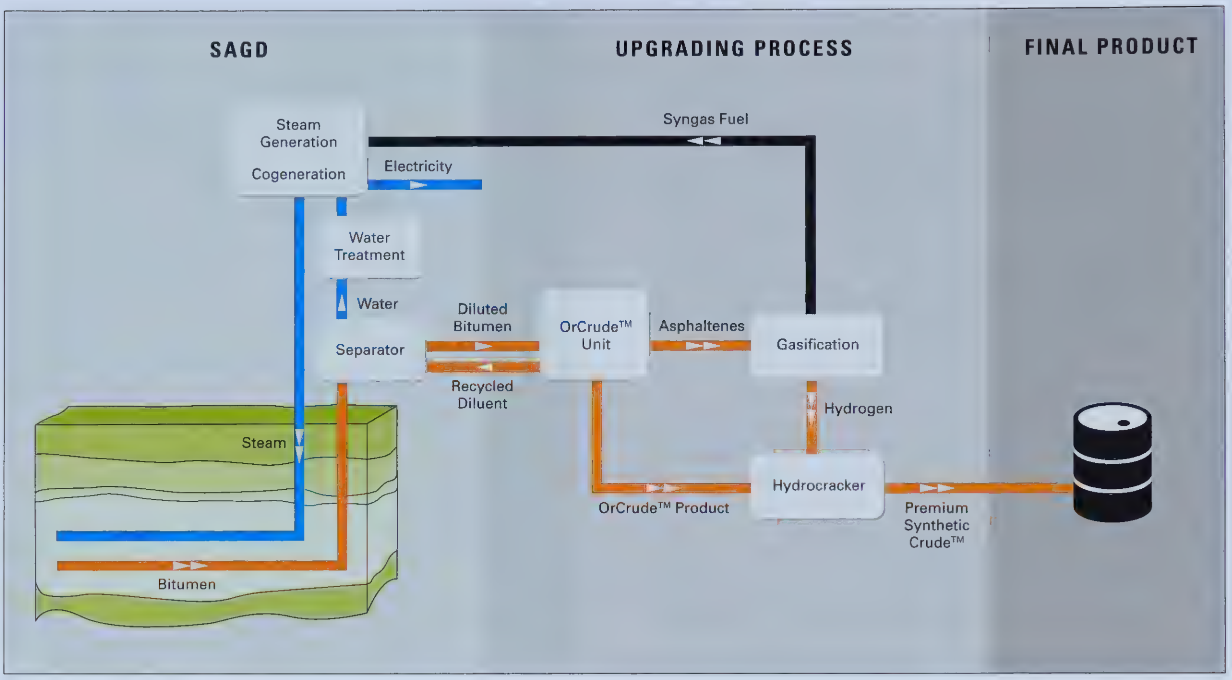
about 90% compared to 75% for a typical bitumen-fed coker, which we expect will provide us with an approximate $10/bbl operating cost advantage.

Our Strategic Advantage

Our integrated SAGD and upgrading process addresses three main economic hurdles of SAGD bitumen production: 1) the high cost of natural gas; 2) the cost and availability of diluent; and 3) the realized price of bitumen. With synthetic gas from the asphaltenes as fuel, we need to purchase very little additional natural gas. With the upgrading facilities on site, expensive diluent is not required to transport the bitumen to market. By upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands light-sweet crude oil premium pricing.

Project Milestones and Costs

The Long Lake Project received regulatory approval in 2003 and Nexen board approval in 2004. Field construction of the SAGD and upgrader facilities began in 2004. In 2006, we substantially completed module and site construction of the SAGD facilities and in 2007, we began injecting steam into the well pads. We continued to steam the SAGD well pairs and began turning wells over to SAGD production in 2008. In 2008, we produced 3,900 bbls/d of bitumen before royalties (3,900 after royalties) and are currently producing approximately 20,000 bbls/d



(13,000 net to us) as of January 2009. The first several months of steam injection largely involves heating the reservoir, followed by a ramp up of bitumen production to peak rates over 12 to 24 months. The reservoir behavior is meeting our expectations. At the start of production, steam-to-oil ratios are high but will decline as bitumen production ramps up to our target rates. We expect the steam-to-oil ratio to average approximately 3.0 over the long-term.

We completed construction of the upgrader in 2008 and began commissioning for commercial operations. Production of premium synthetic crude oil from the upgrader began in late January 2009. We expect that it will take approximately 12 to 18 months to reach the upgrader design capacity. As the upgrader ramps up to full capacity, we expect that there will be periods of downtime as we work through the early stages of operation. This periodic downtime is normal following initial facility start-up and consistent with industry experience. During the bitumen ramp up period, we are purchasing third-party bitumen to take advantage of excess upgrading capacity. Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (39,000 net at a 65% working interest) of premium synthetic crude. We expect to maintain production over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

Long Lake's total capital costs increased since project sanctioning due to design enhancements and industry cost pressures. As a result, the final cost of Long Lake increased from \$3.8 billion to \$6.4 billion (\$3.2 billion net to us before acquiring an additional 15% interest in January 2009). Despite capital cost increases, we still expect to achieve positive economic returns which benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average about \$22/bbl, substantially lower than coking or other upgrading processes as a result of the reduced need to purchase natural gas. We expect ongoing capital to average between \$5/bbl and \$10/bbl depending on well spacing, well length and recovery factor. The full-cycle capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

Future Phases

We have approximately 281,000 net acres of bitumen-prone lands in the Athabasca region, with plans to acquire more. We plan to continue developing our bitumen lands in phases using our integrated upgrading strategy. In 2008, we invested \$175 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for these phases.

During 2007, the federal government announced climate change proposals, however, legislation has not yet been drafted. Due to this regulatory uncertainty and the current global economic crisis, we are delaying certain planned expenditures on Phase 2. Phase 2 is expected to be followed by additional phases every three or four years. Each phase will leverage the knowledge and experience gained from successfully developing Long Lake and subsequent projects will be similar in size and design. By keeping the core team in place and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

Reserves Recognition

Under current SEC rules and regulations, we are currently required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce and sell. The economic recoverability of bitumen reserves is sensitive to natural gas prices, diluent costs and light/heavy differentials, risks that our integrated project has been designed to virtually eliminate. At December 31, 2008, we recognized proved bitumen reserves of 285 mmboe before royalties (282 mmboe after royalties) for our Long Lake Project, representing about 29% before royalties (30% after royalties) of our total proved oil and gas and Syncrude reserves.

Heavy Oil

Approximately 49% of our Canadian conventional production is heavy oil. Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Therefore, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also receives a lower price than light oil, as more expensive and complex refineries are required to refine heavy crude into higher-value petroleum products. To maximize heavy oil returns, it is important to manage capital and operating costs. Our large production base and existing infrastructure are advantageous in managing these costs. Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs, leaving substantial amounts of oil in the ground. This creates an opportunity to increase recovery factors by applying new technology. We are continuing to research various technologies to increase our heavy oil recoveries with ongoing pilot projects in west-central Saskatchewan.

Natural Gas

Approximately 32% of our Canadian production is natural gas extracted primarily from shallow sweet reservoirs in southern Alberta and Saskatchewan and from sour gas reservoirs near Calgary. In general, shallower gas targets are cheaper to drill and produce, but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulphide. Our Balzac field, northeast of Calgary, has been producing sour natural gas since 1961. This sour gas is processed through our operated Balzac plant, which recently went through an extensive maintenance upgrade to improve reliability and efficiency.

Coalbed Methane (CBM)

Approximately 19% of our Canadian production is from our commercial CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area of central Alberta. We began commercial operations in the Upper Mannville coals in 2005, progressively developing opportunities on our land base. We are applying horizontal well technology to increase gas production rates and reduce de-watering time from water-saturated coal. Upper Mannville coals are generally deeper than the Horseshoe Canyon "dry coal" play, which is also being commercially developed in Alberta.

At the end of 2008, we held more than 725 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. In 2009, we plan to tie-in existing wells, drill additional wells, fund anticipated partner-initiated development and invest in new potential CBM plays in the Wetaskiwin and Camrose areas.

Shale Gas

As part of our growth strategy in unconventional Canadian resource plays, we have approximately 195 net sections of land in an emerging Devonian shale gas play in the Horn River Basin in northeastern British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces, fractures or absorbed into organic matter. Currently, the United States is the largest producer of shale gas.

This shale gas play has the potential to become a significant resource play in North America. It has been compared to the Barnett Shale in Texas as it displays similar rock properties and play characteristics. To date, we have invested $340 million in land, infrastructure and wells in the Horn River Basin to progress our shale gas strategy toward potential development and reserve recognition. Five horizontal and three vertical wells were drilled on our lands to evaluate the resource potential. Initial production test results are meeting expectations in terms of resource, initial production and decline profile. In 2009, we plan to continue our evaluation program, furthering our technical experience in the play and to test drilling and completion designs for potential commercial development.

We have approximately 88,000 acres in the Dilly Creek area of the Horn River basin with a 100% working interest.

Limited infrastructure of gas pipeline and processing capacity in the Horn River Basin could potentially constrain early development of our lands. To ensure sufficient gathering, processing and transportation capacity for our early development programs, we have contracted gas pipeline capacity of 96 mmcf/d during a five year term. We have entered into additional agreements that will allow us to participate in projects that are expanding infrastructure in the region.

Fiscal Terms

In Canada, we pay two types of royalties to federal and provincial governments on production from lands where they own the petroleum and natural gas rights. The first type of royalty, Net Profits Interest (NPI), applies to our oil sands projects. The second type is a gross royalty (Gross Royalty) system whereby we pay royalties ranging from 5% to 40% depending upon drilling date, production rate and product sales price.

During 2008, the Alberta government legislated a new royalty framework for NPI and Gross Royalty structures effective January 1, 2009. The new NPI royalty rates for oil sands projects will range from 1% to 9% of gross revenue for projects that are pre-payout of costs, and from 25% to 40% of net profit for projects that are post-payout. These royalty rates vary depending on Canadian dollar equivalent of WTI (Cdn$55/bbl to Cdn$120/bbl). The amended Gross Royalty system increases the upper royalty rate limit to 50% and reduces the lower limit for conventional oil to nil, depending on production rates and sales price. Most of our conventional Alberta production qualifies for lower productivity rates and we expect royalties to range between 5% and 25%.

In addition to royalties, some provinces impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to crown royalties, ranging from 1.7% to 3.0%. In Alberta, we are subject to a freehold mineral tax of approximately 4%.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2007, the Federal government reduced the federal corporate income tax rate, ultimately to 15% by 2012. In 2008, federal taxable income is taxed at 19.5%. Provincial income tax rates vary from approximately 10% to 16%.

Middle East—Yemen

Yemen has been a significant international region for us since we first began production at Masila in 1993. We operate the country's largest oil project and have developed strong relationships with the government and local communities.

Our strategy in Yemen is to maximize the value from our existing blocks, prior to contract expiry. We operate from two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2008, we produced 56,600 bbls/d of oil before royalties (30,600 after royalties), representing approximately 23% of Nexen's total production. Proved reserves of 31 mmboe before royalties (20 after royalties) comprise approximately 3% of Nexen's total proved oil and gas and Syncrude reserves before royalties (2% after royalties).

Masila Block (Block 14)

We operate the Masila Project with a 52% working interest. Our share of 2008 production was 45,900 bbls/d before royalties (24,400 after royalties). The Masila fields are mature, but significant value still remains. As a result of the Production Sharing Agreement (PSA) terms that govern Masila production, we still expect to generate approximately 15% of total project free cash flow before the PSA expires in late 2011.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993, with the first lifting of oil in August 1993. Masila Blend oil averages 32° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations. Production is collected at our Central Processing Facility (CPF) where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal on the Indian Ocean and shipped to customers, primarily in Asia.

Under the Masila PSA, which was signed between the Government of Yemen and the Masila joint venture partners (Masila Partners), we have the right to produce oil from Masila into 2011 and can negotiate a five-year extension. Production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all exploration, development, and operating costs that are funded by the Masila Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for four years
Development	16.7% per year for six years

The remaining production is profit oil that is shared between the Masila Partners and the Government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20% to 33%. The structure of the agreement moderates the impact on the Masila Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the Government. The Government's share of profit oil includes a component for Yemen income taxes payable by the Masila Partners at a rate of 35%. In 2008, the Masila Partners' share of production, including recovery of past costs, was approximately 38%.

East Al Hajr Block (Block 51)

The first successful exploratory well was drilled at BAK-A in 2003, with BAK-B discovered shortly after. Block 51 development began in 2004 and included a CPF, gathering system and a 22 km tie-back to our Masila export pipeline. Production began in November 2004. During 2008, production averaged 10,700 bbls/d before royalties (6,200 after royalties).

We operate Block 51, which is also governed by a PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners): The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures and therefore, our effective interest is 100% and for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. We recognize both the Government's share and TYCO's share of profit oil under the PSA as royalties and taxes consistent with our treatment of our Masila operations. The PSA expires in 2023 and we have the right to negotiate a five-year extension. Under the PSA, the EAH Partners pay a royalty ranging from 3% to 10% to the Government depending on production volumes. The remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen. Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% in year one, 25% in year two
Development	75% in year one, 25% in year two

The remaining production is profit oil that is shared between the EAH Partners and the Government on a sliding scale based on production rates. The EAH Partners' share of profit oil ranges from 20% to 30%. The Government's share of profit oil includes a component for Yemen income taxes payable by the EAH Partners at a rate of 35%. In 2008 the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 47%.

Offshore West Africa

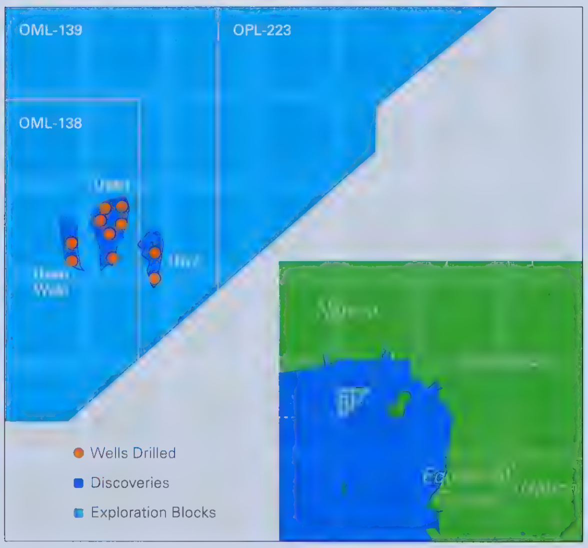
Offshore West Africa is a core area where we already have discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to explore and develop our portfolio for medium- to long-term growth.

Nigeria

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which covers 448,000 acres approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. In 1998, we discovered the Ukot field and encountered three oil-bearing intervals. This was followed up by a successful appraisal well in 2003. In 2002, the Usan field was discovered and seven more successful wells confirmed that significant hydrocarbons exist on the block. In 2008, we acquired an 18% non-operated interest in Block OPL-223, covering 230,000 acres, which provides us with future exploration potential on the adjacent block.

The Nigerian government approved converting OPL-222 into two OMLs (Oil Mining Lease) that will allow the joint venture partners to develop the Usan and Ukot discoveries. OML-138 consists of 50% of the original acreage and includes the Usan discovery. OML-139 consists of the remaining OPL-222 acreage and includes the Ukot discovery.

Appraisal of the Usan field is complete and development of the field is progressing. Major contracts for construction of the FPSO and subsea facilities were awarded during 2008. The project will have the ability to process an average of 180,000 bbls/d of oil during the initial production plateau period through a new FPSO with a two million barrel storage capacity. We expect our share of development and construction costs will be approximately US$2 billion with first production in 2012. In 2009, we plan to progress with the Usan development program. This will include completing detailed engineering, procurement of remaining equipment, fabrication of the FPSO, and initiation of development drilling. At year-end 2008, proved reserves of 28 mmboe before royalties (25 after royalties) comprise approximately 3% of our total proved oil and gas and Syncrude reserves.



Other International

Colombia

In 2000, we made a discovery at Guando on our 20% non-operated Boqueron Block and production from Guando began in 2001. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Our working interest in Guando will decrease to 10% once the field has produced 60 million barrels of oil, which is expected to occur in mid 2009. Our share of 2008 production averaged 5,800 bbls/d before royalties (5,300 after royalties), about 2% of Nexen's total production including Syncrude. We also hold three exploration blocks in the Upper Magdalena Basin that we are assessing for future growth opportunities.

Production from Guando is subject to a royalty between 5% and 25% depending on daily production, and in 2008 averaged 8%. Colombian taxable income is subject to federal income tax of 33% in 2009 and future years.

Norway

Norway is an extension of our conventional offshore growth strategy in the North Sea. The Norwegian North Sea is an established area that has significantly developed infrastructure and relatively unexplored basins that provide the potential for future growth. The Norwegian government created incentives for the oil and gas industry to explore by providing 78% cash tax refunds on qualifying exploration expenditures to companies that do not have a taxable income base. We have ten offshore exploration licences in the Norwegian North Sea with plans to drill our first exploration well in the near future. In 2009, we expect to invest in seismic and geologic studies.

Norwegian oil and gas activities are subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax.

RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Net Sales by Product from Oil and Gas Operations (including Syncrude)

(Cdn$ millions)	2008	2007	2006
Conventional Crude Oil and Natural Gas Liquids (NGLs)	5,534	4,077	2,479
Synthetic Crude Oil	691	545	446
Natural Gas	652	499	553
Total	**6,877**	**5,121**	**3,478**

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 90% of our oil and gas net sales, while natural gas represents the remaining 10%.

Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price[1]			Average Production Cost[1]		
	2008	2007	2006	2008	2007	2006
Crude Oil and NGLs (Cdn$/bbl)						
United Kingdom	96.23	76.30	71.19	6.75	6.94	11.28
Yemen	99.87	76.29	71.57	15.88	12.00	8.11
Canada	74.51	44.07	42.79	22.16	18.67	15.50
United States	104.94	69.83	65.80	13.48	9.69	9.45
Other Countries	98.98	71.29	66.09	4.91	3.76	3.13
Natural Gas (Cdn$/mcf)						
United Kingdom	6.78	4.71	7.43	1.12	1.16	1.88
Canada	7.73	6.32	6.49	2.09	2.28	1.65
United States	10.07	7.80	7.86	2.25	1.61	1.58

1 Sales prices and unit production costs are calculated using our working interest production after royalties.

Oil and Gas Acreage

	Developed		Undeveloped[1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United Kingdom	197	81	1,107	752	1,304	833
Yemen[2]	50	29	756	628	806	657
Canada	817	634	1,865	985	2,682	1,619
United States	215	125	1,260	630	1,475	755
Colombia[4]	1	–	607	372	608	372
Nigeria[2,3]	–	–	678	131	678	131
Norway	–	–	680	383	680	383
Total	**1,280**	**869**	**6,953**	**3,881**	**8,233**	**4,750**[5]

1 Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.
2 The acreage is covered by production sharing contracts.
3 The acreage is covered by a joint venture agreement.
4 The acreage is covered by an association contract.
5 Approximately 20% of our net oil and gas acreage is scheduled to expire within three years if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licences.

Producing Oil and Gas Wells

(number of wells)	Oil Gross[1]	Oil Net[2]	Gas Gross[1]	Gas Net[2]	Total Gross[1]	Total Net[2]
United Kingdom	50	22	–	–	50	22
Yemen	540	327	–	–	540	327
Canada	2,258	1,571	3,124	2,743	5,382	4,314
United States	183	94	202	142	385	236
Colombia	117	24	–	–	117	24
Total	**3,148**	**2,038**	**3,326**	**2,885**	**6,474**	**4,923**

1 Gross wells are the total number of wells in which we own an interest.
2 Net wells are the sum of fractional interests owned in gross wells.

Drilling Activity

2008

(number of net wells)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total
United Kingdom	2.5	2.0	4.5	3.3	–	3.3	7.8
Yemen	–	1.0	1.0	17.4	–	17.4	18.4
Canada	9.2	–	9.2	216.4	–	216.4	225.6
United States	0.5	1.0	1.5	1.3	–	1.3	2.8
Colombia	–	–	–	1.6	–	1.6	1.6
Total	**12.2**	**4.0**	**16.2**	**240.0**	**–**	**240.0**	**256.2**

2007

(number of net wells)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total
United Kingdom	2.0	3.2	5.2	4.2	–	4.2	9.4
Yemen	1.0	1.0	2.0	28.0	–	28.0	30.0
Canada	23.2	0.6	23.8	295.6	3.2	298.8	322.6
United States	0.8	2.9	3.7	8.6	1.0	9.6	13.3
Colombia	–	0.9	0.9	7.0	–	7.0	7.9
Total	**27.0**	**8.6**	**35.6**	**343.4**	**4.2**	**347.6**	**383.2**

2006

(number of net wells)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total
United Kingdom	0.8	1.7	2.5	5.5	–	5.5	8.0
Yemen	3.0	5.5	8.5	36.0	1.0	37.0	45.5
Canada	35.4	2.2	37.6	214.3	0.7	215.0	252.6
United States	1.6	2.1	3.7	8.3	2.0	10.3	14.0
Colombia	–	–	–	2.0	–	2.0	2.0
Nigeria	–	0.2	0.2	–	–	–	0.2
Total	**40.8**	**11.7**	**52.5**	**266.1**	**3.7**	**269.8**	**322.3**

Wells in Progress

At December 31, 2008, we were drilling four wells in Yemen (2.1 net), 16 wells in Canada (10 net), one well in the United States (0.4 net) and seven wells in the United Kingdom (4.5 net). There were no wells drilling in Colombia at December 31, 2008.

Proved Reserves including Proved Undeveloped Reserves

At December 31, 2008, we had 664 mmboe of proved oil and gas reserves before royalties. This is a 10% decrease over the prior year. Including Syncrude, our total proved oil and gas and Syncrude reserves decreased 7% to 988 mmboe. The decrease resulted as additions from our capital program and positive technical revisions of previous estimates did not offset production and negative economic revisions from the decline in year-end oil and gas prices. On an after-royalty basis, our proved oil and gas reserves decreased 3% to 631 mmboe and increased 1% to 926 mmboe when including Syncrude reserves. The changes on an after-royalties basis reflect a reduction in royalties primarily at our oil sands projects where the royalties are sensitive to oil prices.

The following table provides a summary of the changes during 2008 in our proved oil and gas reserves (before royalties) excluding our Syncrude reserves. Refer to page 126 for proved reserves information on an after-royalties basis.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2007	386	207	62	41	38	734
Extension and Discoveries	27	5	1	1	–	34
Revisions – Technical	5	17	(1)	11	–	32
Revisions – Economic	(27)	(16)	(5)	–	(2)	(50)
Acquisitions	–	–	–	–	–	–
Divestments	–	–	–	–	–	–
Production	(16)	(38)	(8)	(22)	(2)	(86)
December 31, 2008	**375**	**175**	**49**	**31**	**34**	**664**

Excluding economic revisions, our net oil and gas reserve additions are 66 mmboe (60 after royalties) and including Syncrude are 74 mmboe (67 after royalties).

Extensions and discoveries of 34 mmboe (33 after royalties) are primarily from extending our Long Lake Project by core hole delineation, development drilling at Buzzard, and ongoing development of coalbed methane in Canada. Other increases relate to ongoing exploitation activities in the North Sea, Yemen, the Gulf of Mexico and Canada. No proved reserves will be recognized for exploration discoveries at Golden Eagle, Pink or Blackbird in the UK until we advance our understanding of these discoveries further and demonstrate a commitment to development.

Positive technical revisions of 32 mmboe (27 after royalties) are primarily from additions at Buzzard, Yemen and Canadian coalbed methane where drilling results and production performance supported higher reserve estimates. Negative technical revisions of 13 mmboe relate primarily to Ettrick where ongoing development drilling and testing did not support previous estimates.

Negative economic revisions of 50 mmboe (7 after royalties) are the result of lower commodity prices (primarily oil) and rising costs at year-end. Under SEC regulations, we are required to use year-end prices and costs to estimate our reserves. About 85% of this revision is price related, of which half occurred in our Canadian heavy oil properties, while the remaining changes occurred at our Buzzard, Ettrick, Scott and Telford fields in the UK, and some of our US shelf properties. The majority of the remaining revisions resulted from higher year-end costs, primarily on our Canadian heavy oil properties.

The following provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding Syncrude, for the past three years. Refer to page 126 for proved reserves information on an after-royalties basis for the past three years.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2005	117	145	90	105	11	468
Extension and Discoveries	45	40	12	7	30	134
Revisions – Technical	27	78	(21)	4	1	89
Revisions – Economic	228	(13)	(8)	–	(2)	205
Acquisitions	–	1	11	–	–	12
Divestments	–	–	(2)	–	–	(2)
Production	(42)	(76)	(33)	(85)	(6)	(242)
December 31, 2008	**375**	**175**	**49**	**31**	**34**	**664**

Since the end of 2005, we added 440 mmboe (431 after royalties), sold 2 mmboe (2 after royalties) and produced 242 mmboe (191 after royalties). Extensions and discoveries of 134 mmboe (122 after royalties) occurred primarily at our Usan, Ettrick and Buzzard fields, Long Lake Project, Canadian coalbed methane, and the deep-water Gulf of Mexico. The net technical revisions of 89 mmboe (81 after royalties) include 78 mmboe (78 after royalties) of positive revisions in the UK primarily attributed to production performance at Buzzard and increased expected recoveries for our Long Lake Project based on analogous commercial SAGD projects. Negative technical revisions occurred primarily from lower-than-expected production performance at our Aspen field and some Shelf properties in the US Gulf of Mexico. Economic revisions of 205 mmboe (218 after royalties) are related to changes in year-end prices and costs. This includes a positive revision of 246 mmboe (245 after royalties) from reinstatement of Long Lake bitumen reserves that we had removed due to low bitumen prices at the end of 2004. This was partially offset by negative revisions of 41 mmboe (27 after royalties) as a result of substantial decline in oil and gas prices at December 31, 2008 versus 2005 and a rising cost environment that has not yet corrected with the decline in commodity prices.

Proved Undeveloped Reserves

The following table provides a summary of the proved undeveloped reserves (PUDs) for our oil and gas activities at the end of the last two years:

	2008					
	Before Royalties			After Royalties		
(mmboe)	**PUDs**	**Total Proved**[1]	**% of Total**	**PUDs**	**Total Proved**[1]	**% of Total**
United Kingdom	40	175	23%	40	175	23%
Yemen	3	31	8%	1	20	7%
Canada	236	375	63%	234	362	65%
United States	11	49	23%	10	43	23%
Other Countries	28	34	82%	25	31	82%
December 31, 2008	318	664	48%	310	631	49%

	2007					
	Before Royalties			After Royalties		
(mmboe)	**PUDs**	**Total Proved**[1]	**% of Total**	**PUDs**	**Total Proved**[1]	**% of Total**
United Kingdom	54	207	26%	54	207	26%
Yemen	2	41	5%	1	23	4%
Canada	236	386	61%	200	334	60%
United States	20	62	32%	17	53	32%
Other Countries	30	38	79%	25	33	76%
December 31, 2007	**342**	**734**	**47%**	**297**	**650**	**46%**

1 Excludes proved reserves for our Syncrude operations of 324 mmboe (295 after royalties) in 2008 and 324 mmboe (267 after royalties) in 2007.

In 2008, our PUDs decreased by 24 mmboe (increased by 13 after royalties). We converted 29 mmboe (26 after royalties) with the start-up of our Long Lake SAGD operations, the substantial completion of our Longhorn development project, and the remainder relating to ongoing development of various other properties. We had negative revisions of 14 million boe (13 after royalties) primarily at Ettrick, and we added 19 mmboe (51 after royalties) with the extension of the Long Lake reservoir. After-royalty changes reflect the impact of lower price-sensitive royalties for our Long Lake Project.

In Canada, our PUDs remained at 236 mmboe before royalties (increased 34 to 234 after royalties). At Long Lake, PUDs increased by 4 mmboe (37 after royalties) due to a 19 mmboe (19 after royalties) addition from ongoing delineation drilling, offset by a 15 mmboe reduction (18 increase after royalties) from conversion to proved with the ongoing start-up of SAGD wells. Other PUDs declined by 4 mmboe (3 after royalties) due to conversions in our coalbed methane properties and revisions in our heavy oil properties. The remaining PUDs are substantially all from Long Lake where we have 232 mmboe (230 after royalties) which are expected to be converted to developed over the next 20 years as we drill additional wells to provide feedstock to run the upgrader at capacity. Other PUDs relate to infill drilling, recompletions or facilities enhancements on our various CBM, heavy oil and natural gas properties. The majority of these PUDs are expected to be converted to producing reserves in 2009 and 2010.

In the United Kingdom, our PUDs decreased from 54 mmboe (54 after royalties) to 40 mmboe (40 after royalties). The decrease primarily reflects the reduction of PUDs at Ettrick. About 75% of the PUDs at December 31, 2008 relate to Buzzard while the remainder relate to Ettrick. At Buzzard, we converted 5 mmboe of PUDs to producing and added 3 mmboe for increased recovery factors on remaining undrilled locations. The Buzzard PUDs are expected to be converted to producing over the next few years as we drill additional wells and develop increased H_2S handling facilities to keep the platform operating at capacity. We expect to convert the majority of Ettrick PUDs to producing when production is initiated in 2009.

In the United States, our PUDs decreased from 20 mmboe (17 after royalties) to 11 mmboe (10 after royalties) largely relating to the completion of the development at Longhorn and conversion and revision of the remaining Gulf of Mexico shelf PUDs. Almost all of the remaining PUDs are located in the deep water of the Gulf of Mexico and relate to suspended production from hurricane damage in our Green Canyon blocks and Gunnison infill drilling. The majority of these PUDs are expected to be converted to producing reserves in 2009 and 2010.

In other countries, PUDs relate primarily to our Usan development, offshore West Africa.

Excluding Long Lake and Usan, we expect to convert over 90% of our PUDs to producing in the next three years. Usan will be converted by 2012 when it is expected to come on stream. Long Lake PUDs will be converted over the next 20 years as new wells are drilled to offset declines from the initial SAGD wells. At the same time, we expect our ongoing exploration and development activities to continue to add new PUDs.

During the past three years, our total PUDs before royalties increased from 180 mmboe to 318 mmboe (165 to 310 after royalties). As a result, our PUDs before royalties as a percent of total proved reserves excluding Syncrude increased from 38% to 48% (42% to 49% after royalties). During this time, we added 206 mmboe (179 after royalties) at our Long Lake Project from the reinstatement of proved reserves previously written off due to low year-end bitumen prices and another 96 mmboe before royalties (119 after royalties), related to our active development projects at Long Lake, Usan, Ettrick, CBM and Longhorn. We converted 164 mmboe before royalties (153 after royalties) to developed with the completion of development of our Buzzard, Farragon and Duart fields in the United Kingdom, Block 51 in Yemen, and ongoing development of work elsewhere.

Basis of Reserves Estimates

Reserve estimates in this report are internally prepared. Refer to the section on Critical Accounting Estimates—Oil and Gas Accounting—Reserves Determination on page 70 for a description of our reserves process. As described therein, we have at least 80% of our oil and gas reserve estimates either evaluated or audited annually by independent qualified reserves consultants. The nature and scope of the independent evaluations and audits is determined by agreement between us and the engineering firm. Independent assessments for other companies may, therefore, be different.

The following provides an overview of the nature and scope of the independent evaluations and audits that we have performed. An independent evaluation is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by assessing and interpreting all available data on a reservoir. An independent audit is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by reviewing our estimates, supporting working papers and other data as necessary. The primary difference is that an auditor reviews our work and estimate in preparing their estimate whereas an evaluator uses the reservoir data to prepare their estimate.

In each case, we request their estimate be prepared using standard geological and engineering methods generally accepted by the petroleum industry. Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used is based on their professional judgement and experience. In preparing their estimates, they obtain information from us with respect to property interests, production from such properties, current costs of operations, expected future development and abandonment costs, year-end prices, agreements relating to current and future operations and sale of production, and various other information and data. They may rely on the information without independent verification. However, if in the course of their evaluation they question the validity or sufficiency of any information, we request that they not rely on such information until they satisfactorily resolve their questions or independently verify such information. We do not place any limitations on the work to be performed. Upon completion of their work, the independent evaluator or auditor issues an opinion as to whether our estimate of the proved reserves for that portfolio of properties is, in aggregate, reasonable relative to the criteria set forth in SEC Rule 4-10(a)(2) of Regulation S-X. These rules define

proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Our estimate may differ from the independent evaluators and auditors as they apply their professional judgement and experience, which may result in applying different estimating methods or interpreting data differently than us. We believe our estimate for a portfolio of properties is reasonable when it is, in aggregate, within 10% of the estimate of the independent evaluator or auditor.

We engaged DeGolyer and MacNaughton (D&M) to evaluate 100% of our reserves before royalties (100% after royalties) for the United Kingdom, Yemen Masila, Yemen Block 51 and Nigeria. A separate opinion was provided on each of these four areas. D&M provided an opinion on each of the areas that the proved reserves estimate prepared by us is, in aggregate, reasonable when compared to their estimate which was prepared in accordance with current SEC Rules.

We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate 99% of our Canadian conventional, CBM and bitumen reserves before royalties (99% after royalties) and to audit 100% of our Syncrude mining reserves before royalties (100% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. McDaniel provided their opinions that the proved reserves estimates prepared by us are, in aggregate, reasonable when compared to their estimates which were prepared in accordance with current SEC Rules.

We engaged Ryder Scott Company (Ryder Scott) to evaluate 92% of our US Gulf of Mexico shelf and deep water reserves before royalties (92% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. Ryder Scott provided an opinion that the difference between their estimate and ours is within the range of reasonable differences and that the estimates have been prepared in accordance with current SEC Rules. In prior years, we engaged William M. Cobb & Associates Inc. to evaluate our deep water reserves. The Reserves Review Committee of the Board was satisfied that the change in evaluator was not the result of a dispute with management.

SYNCRUDE MINING OPERATIONS

We hold a 7.23% participating interest in Syncrude. This joint venture was established in 1975 to mine shallow oil sands deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil. Syncrude's operating strategy is to develop this resource, focusing on safe, reliable and profitable operations.

Syncrude exploits a portion of the Athabasca oil sands that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14 percent by weight and ore bearing sand thickness of 100 to 160 feet. Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31, and 34) covering 248,300 hectares, 40 km north of Fort McMurray in northeast Alberta. Syncrude mines oil sands at two mines: Mildred Lake North and Aurora North. These locations are readily accessible by public road. Trucks and shovels are used to collect the oil sands in the open pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 270 million tons of oil sands per year and between 150 to 160 million barrels of bitumen per year depending on the average bitumen ore grade. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Mildred Lake North Mine uses hot water, steam and caustic soda to create a slurry, while at the Aurora North Mine, the oil sands are mixed with warm water to produce a slurry. Most of the water used in operations is recycled from the upgrader and mine sites. Incremental water is drawn from the Athabasca River in accordance with existing licenses.

The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading. The resulting products are then separated into naphtha, light gas-oil, and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2008, about 40% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 60% was sold to refineries in eastern Canada and the mid-western United States. Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than 1.9 billion barrels of synthetic crude oil to Edmonton by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.

At December 31, 2008, our total net book value of property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities, was approximately $1.1 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about $5.2 billion.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating license for the eight oil sands leases through to 2035. The license permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start up of operations in 1978.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 25 miles north of the main Syncrude site. The next expansion of Syncrude came on stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project.

Syncrude pays a royalty to the Alberta government. As of January 2002, this royalty was equal to the greater of 1% of gross revenue or 25% of net synthetic-based profit after deducting new capital expenditures. In connection with the provincial government's review of Alberta royalty rates in 2007, the Syncrude owners entered into negotiations at the request of the government to revise the royalty terms. Effective January 1, 2009, and consistent with the rest of the oil sands industry, Syncrude will begin paying royalties based on bitumen product, rather than paying royalties calculated on fully upgraded synthetic crude oil. As a part of this conversion, the Alberta government will recapture upgrader capital expenses of about $5 billion (gross) that were deducted against prior royalties payables. The $5 billion royalty deductions previously received by the Syncrude owners will be recaptured by the Alberta government over a 25 year period. In addition, the Province of Alberta and Syncrude reached an agreement to establish new transitional royalty terms. Under the terms of the agreement, until December 31, 2015, Syncrude will continue to pay base

royalty rates (being the greater of 25% of net bitumen-based revenues, or 1% of gross bitumen-based revenues) plus an incremental royalty of up to $975 million (our share $70.5 million). The incremental royalty is subject to certain minimum bitumen production thresholds and is to be paid in six annual payments, as indicated in the following table:

(Cdn$ millions)	2010	2011	2012	2013	2014	2015	Total
Gross	75	75	100	150	225	350	975
Nexen's Share	5	5	7	11	17	25	70

This agreement is in lieu of the Syncrude owners converting to the Province's new royalty framework announced in October 2007, that is effective January 1, 2009. After January 1, 2016, the rates under the new royalty framework will apply to the Syncrude project.

In 2008, Syncrude's production of marketable synthetic crude oil was 289,100 bbls/d. Nexen's share was 20,900 bbls/d before royalties (18,200 after royalties). At year end, Syncrude reserves of 324 mmboe before royalties (295 after royalties) represented about 33% of our total proved oil and gas and Syncrude reserves.

The following table provides some operating statistics for Syncrude operations:

	2008	2007	2006
Total Mined Volume[1]			
Millions of Tons	531	470	428
Mined Volume to Oil Sands Ratio[1]	2.5	2.1	2.2
Oil Sands Processed			
Millions of Tons	216	220	192
Average Bitumen Grade (weight %)	11.1	11.6	11.3
Bitumen in Mined Oil Sands			
Millions of Tons	24	26	22
Average Extraction Recovery (%)	90	92	90
Bitumen Production[2]			
Millions of Barrels	122	133	112
Average Upgrading Yield (%)	86	84	85
Gross Synthetic Crude Oil Shipped[3]			
Millions of Barrels	105.8	111.3	94.3
Nexen's Share of Marketable Crude Oil			
Millions of Barrels Before Royalties	7.7	8.1	6.8
Millions of Barrels After Royalties	6.6	6.9	6.2

1 *Includes pre-stripping of mine areas.*
2 *Bitumen production in barrels is equal to bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.*
3 *Approximately 1% of the produced synthetic crude oil is used internally, primarily for diesel that fuels the trucks and shovels at Syncrude. The remaining synthetic crude oil is sold externally.*

ENERGY MARKETING

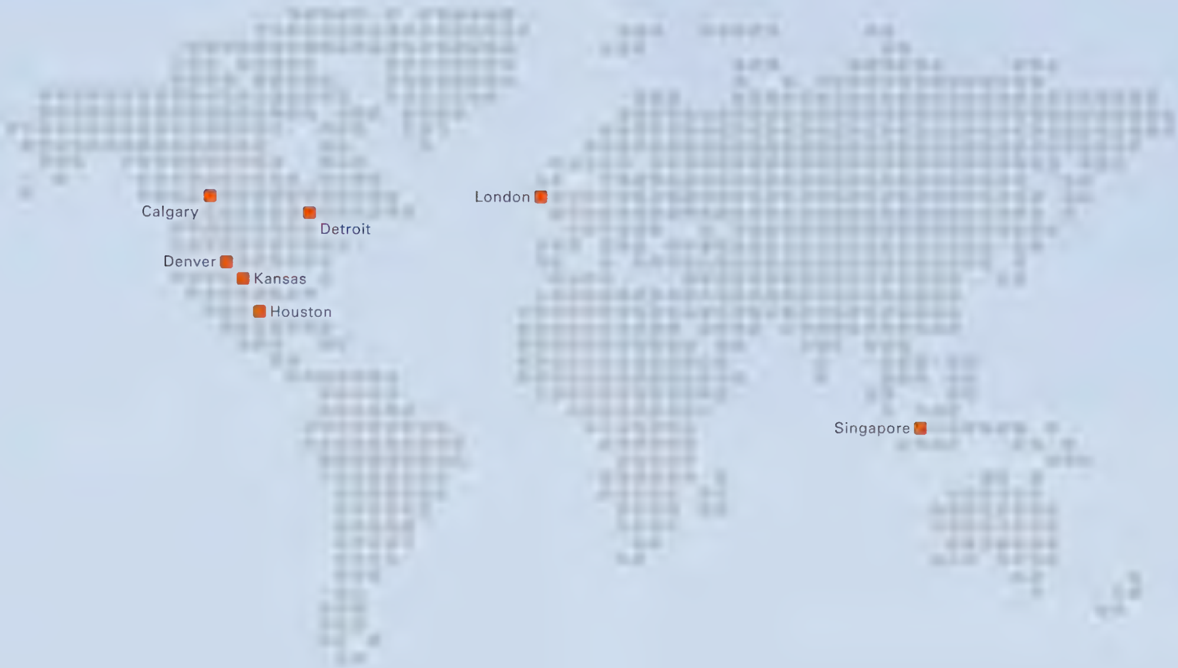
Our marketing group sells proprietary and third-party natural gas, crude oil, natural gas liquids, and power in certain regional global markets. We have built a solid strategic presence within various North American regional markets and have extended our presence into certain global markets. We focus on securing access to transportation, storage and facilities, as well as the commodities we produce or acquire. We optimize the margin on our base business by physically and financially trading around our access to these physical assets. We also trade financially for profit where we see opportunities in the market. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our oil and gas production;
- provide market intelligence in support of our oil and gas operations;
- provide superior customer service to producers and consumers;
- capitalize on market opportunities through physical and financial trading; and
- optimize physical assets or contracts to which we have access.

This strategy aligns with our corporate focus on realizing the full value from our assets and provides us with the market intelligence needed to deliver current and future oil and gas production to market at competitive pricing.

Marketing Office Locations



North American Gas Marketing

The marketing and trading of North American natural gas has historically been our marketing group's largest revenue source. We focus on key regional markets where we have a strategic presence, equity production, solid customer relationships, in-depth understanding of the market or established physical assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further revenue by:

- capitalizing on location spreads (differences in prices between locations) using our transportation assets;
- offering customized service to our customers that bundle our assets with the commodity;
- utilizing our storage assets where we optimize forward and seasonal pricing differences; and
- leveraging regional knowledge we gain through optimizing our assets.

We have offices in key regions including Calgary, Detroit, Denver and Houston. Our offices provide a variety of services, including supply, storage, and transportation management as well as netback pool arrangements and other customer services. Our customers include producers and consumers (including utilities) in western Canada, eastern Canada, the northeastern US, the US mid-continent, the Pacific northwest and the US Rockies. We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

Over the years, we focused on growing our asset base by acquiring physical gas purchase and sales contracts, as well as natural gas transportation and storage capacity, on favourable terms. The growth in our underlying physical business was supplemented by an expanding profitable financial trading business with a focus on time and location spreads. In 2008, financial trading proved particularly challenging causing us to reassess the merits of this activity. While we expect to continue to focus on our core physical business, we are reducing our financial trading levels and exposures in an orderly fashion.

Our position as a physical marketer at multiple delivery points in key markets gives us flexibility to capitalize on time and location spreads. With pipeline capacity, we can move gas from producing to consuming regions to take advantage of price differences. At the end of 2008, we held 1.8 bcf/d of pipeline capacity, primarily between western Canada and the eastern US. We also use storage capacity to store normally cheaper summer gas in the ground until the winter heating season arrives. We had access to 38 bcf of natural gas storage facilities at the end of the year.

In addition to transportation and storage assets, we enter into financial contracts that enable us to capture profits around time and location spreads. The risks we assume on these contracts are based on fundamental analysis and knowledge of regional markets. The risk is managed by our product group teams and monitored by our risk group, with regular reporting to Management and the Board of Directors.

North American Crude Oil Marketing

Our crude oil business focuses on marketing physical crude oil to end-use refiners. The crude oil group markets Nexen's production and more than 650,000 bbls/d of third-party production. In addition to physical marketing, we take advantage of quality, time and location spreads.

Our North American operations focus on key regions supported by our offices in Calgary, Houston and Denver. In western Canada, our producer services group concentrates on purchasing from a diversified supply base, while our trading team seeks to optimize the mix for sale to refiners. The Chicago and Denver areas have been key markets for our western Canadian crude, however, we continue to expand our presence into the US Gulf Coast. Our deep-water Gulf of Mexico crude oil production expanded our presence in that market through our Houston office. At the end of 2008, we had access to 2.6 mmbbls of storage and over the course of the year, marketed approximately 656 mbbls per day.

Our operations also include a North American natural gas liquids (NGLs) business that focuses on buying and selling NGLs. This business acquires and moves product within North America. At the end of 2008, we had access to 1.2 mmbbls of NGL storage and over the course of the year, moved approximately 26 mbbls per day of product. In 2008, we were active in the ethanol markets in North America but we expect to turn our focus to more traditional NGL markets in 2009.

Our crude oil marketing group also enters into financial contracts intended to capture trading profits around time, quality and location spreads. Like gas marketing, the risks assumed are based on fundamental analysis and proprietary knowledge of regional markets, and are monitored by our risk group.

North American Power Marketing

Our power marketing group is responsible for optimizing our 50% interest in a 120 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, as well as our 50% interest in the 70 MW Soderglen wind power operation in southern Alberta. We also market the surplus power from the 170 MW cogeneration facility at Long Lake (Nexen 65% interest) that commenced operation in 2008. We market power to larger commercial, industrial and municipal clients in Alberta. We are currently the largest supplier of power to commercial and industrial sectors in the province. Our Balzac facility began operations in 2001 and Soderglen in October 2006.

Europe

Our European operations include a UK-based European gas and power marketing business. Our trading strategies include capitalizing on time and location spreads involving the UK and European gas and power markets, using primarily financial contracts. We are increasing our presence in both the UK and continental Europe physical gas markets. During the year, we secured access to transportation and storage capacity in the UK and Europe. At the end of 2008, we had access to 0.1 bcf/d transportation capacity and 3.7 bcf of storage capacity. Our European marketing operations also physically market our Buzzard crude oil production.

Asia

Our international team in Asia continues to focus on the physical marketing of Masila crude oil. In order to meet customer needs, we occasionally market other regional crude qualities. In addition to our own crude, we sell production for our partners and third parties in the Yemen region. By locating our international crude oil marketing office in Singapore, we are well positioned to serve both the producing region and the Asian refining market.

CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. We currently hold a 63.5% interest in our chemicals business, and continue to fully consolidate chemicals in our Consolidated Financial Statements.

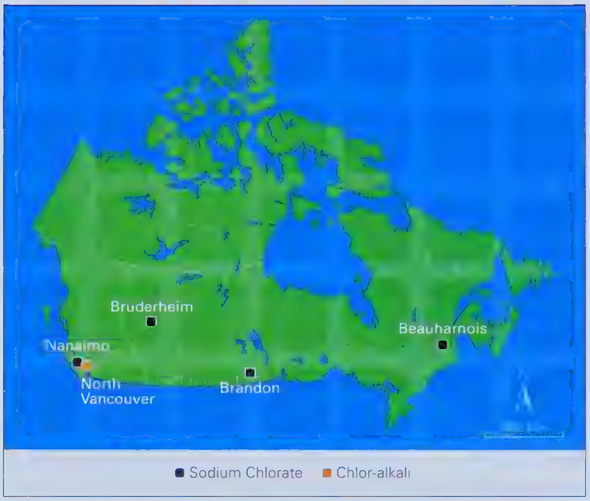
Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing system is reliable, low-cost and strategically located to capitalize on competitive electricity costs and transportation infrastructure to minimize production and delivery costs.

Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products, making up over half our cash costs. Therefore, our current facilities are strategically located to take advantage of economic power sources. Our second highest cost is transportation. The proximity of our manufacturing plants to major customers and competitive freight rates minimize our transportation costs. Labour is also a significant manufacturing cost. Approximately 50% of our workforce is unionized with collective agreements in place at all of our unionized plants.

To grow value in our chemicals business, we focus on reducing our costs while maintaining market share, building a sustainable North American customer base and capturing new offshore opportunities. In 2009, we will fund our current capital projects from undistributed cash, dividend reinvestment and existing credit facilities (which were renewed in 2008).

North America

The North American pulp and paper industry consumes approximately 93% of the continent's sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume adjustment provisions. Approximately 27% of this production is sold in Canada, 66% in the US, and the rest is marketed offshore.



We are the third-largest manufacturer of sodium chlorate in North America with four Canadian facilities: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; and Beauharnois, Quebec.

In 2008, we completed an expansion of our Brandon plant, increasing capacity to over 290,000 tonnes per year. Brandon is the world's largest sodium chlorate facility and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America.

Our chlor-alkali facility at North Vancouver, British Columbia, manufactures caustic soda, chlorine and muriatic acid. Almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl, chloride, water purification and petrochemicals industries, primarily in the United States. A technology conversion project currently under way will replace existing diaphragm technology and assets with newer, proven membrane technology that is expected to be more cost effective and will expand productive capacity by 35%. This project is progressing on time and on budget with committed financing in place through to August 2011. The project is expected to start up in the first quarter of 2010 and should lower our cost structure and solidify our low-cost position in this regional market.

Average Annual Production Capacity

(short tons)	2008	2007	2006
Sodium Chlorate			
North America	484,800	450,055	446,208
Brazil	68,563	68,563	68,563
Total	**553,363**	**518,618**	**514,771**
Chlor-alkali			
North America	364,500	364,500	356,002
Brazil	109,430	109,430	109,430
Total	**473,930**	**473,930**	**465,432**

Brazil

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Cellulose S.A. (Aracruz), the leading manufacturer of pulp in Brazil. The majority of the sodium chlorate production is sold to Aracruz under a long-term sales agreement that expires in 2024. Most of the chlorine and about 8% of the sodium chlorate production is sold in the merchant market under short-term contracts. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. A 2,000 tonne incremental sodium chlorate expansion project is currently in progress at our Brazil plant and is scheduled for start up in early 2009. A further 4,400 tonne expansion was recently approved, which is estimated to start up in early 2010. The majority of our electricity needs in Brazil are supplied by a long-term supply contract, which expires in February 2013.

GOVERNMENT REGULATIONS

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We participate in many industry and professional associations and monitor the progress of proposed legislation and regulatory amendments.

ENVIRONMENTAL REGULATIONS

Our oil and gas, Syncrude and chemical operations are subject to government laws and regulations designed to protect and regulate the discharge of materials into the environment in countries where we operate. We believe our operations comply, in all material respects, with applicable environmental laws. To reduce our exposure, we apply industry standards, codes and best practices to meet or exceed these laws and regulations. We may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

We have an active Health, Safety, Environment and Social Responsibility group (HSE&SR) that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner. Our HSE&SR practices are reported to our Board of Directors throughout the year. Our overall HSE&SR program is guided by the following 12 element management system:

- leadership and commitment;
- regulatory compliance;
- safety and occupational health management;
- social responsibility;
- environmental management;
- supply chain management;
- documentation and procedure management;
- training and awareness;
- process safety management;
- emergency preparedness;
- event reporting, investigation and follow-up; and
- continuous improvement.

Our performance against this system is reviewed by an external auditor every three years and we have been recognized by the Dow Jones Sustainability Index as a global sustainability leader for eight years in a row. Our progress is publicly reported in our sustainability report which is available on our website at www.nexeninc.com.

Climate Change and Environmental Responsibilities

A growing awareness of possible causes and effects of climate change along with volatile consumer prices have increased concern over the manner by which the world produces and consumes energy. Government and investor expectations continue to converge on sustainable resource development and responsible operating practices, including the preservation of air, water and land. Some jurisdictions in which we operate have already formalized these expectations into regulation while others move closer to doing so. Regardless of how the jurisdictions in which we operate ultimately define their emissions regulation, we expect that our regulatory obligations and the associated cost of compliance will increase. Due to the uncertainty surrounding the future implementation of emissions regulations, we are unable to estimate our costs of compliance.

As a result of our commitment to sustainable development and responsible operating practices, we believe we are well positioned to meet the challenges of climate change and environmental regulation. We have built a corporate culture of integrity and respect for the communities and environments in which we operate, and have developed policies and practices for continuing compliance with all environmental laws and regulations.

Air

To meet our current greenhouse gas (GHG) emissions obligations, we adhere to a five point emissions management strategy:

- reduce emissions by decreasing vent gas and improving energy efficiency;
- self-generate carbon credits from wind power;
- acquire carbon credits through qualified offshore projects, such as the Greenhouse Gas Credit Aggregation Pool (GGCAP);
- participate in eligible international and domestic offset projects such as methane capture from landfills; and
- purchase carbon credits on the spot market.

Water

We are developing a company-wide water management strategy to limit water use. An external consulting firm compiled information on water issues relevant to Nexen's projects and operations, reviewed key business drivers related to water, and surveyed Nexen's business units with respect to their water policies and practices. Benchmarking of oil and other industry related water policies, strategies and programs was also completed. This information was used as the starting point for our HSE&SR group to begin the process of developing corporate water management principles that are aligned with our stated objective to "grow value responsibly".

Land

Our land use practices are based upon principles of minimal disturbance and a commitment to return land to its natural state after responsibly producing oil and gas resources. We also recognize our ability to effectively access land is directly linked to the way in which we manage potential environmental effects and in how we cooperate with other industries to reduce our cumulative impact.

For many stakeholders, a company's ability to meet environmental expectations is a significant criteria upon which their decision to invest or conduct business is based. A failure to meet those expectations can limit access to exploration, development and partnership opportunities. We therefore believe that superior environmental and social responsibility performance is directly linked to economic performance.

We have outlined and more fully discussed our environmental practices and policies in our sustainability report, available on our website at www.nexeninc.com.

Environmental Provisions and Expenditures

Meeting the challenges of climate change and environmental regulation and our commitment to sustainable resource development increases the cost of our operations. The ultimate financial impact of our sustainability practices and compliance with environmental laws and regulations is not clearly known and cannot be reasonably estimated as new standards continue to evolve in the countries in which we operate. We estimate our future environmental costs based on past experience and current regulations. At December 31, 2008, $1,059 million ($2,393 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations. In 2008, we increased our retirement obligations for future dismantlement and site restoration by over $200 million primarily from ongoing development of the

Long Lake Project in the Athabasca oil sands, our CBM wells in Canada and from industry cost pressures in the North Sea and the US Gulf of Mexico.

In 2008, our expenditures for environmental-related matters, including environment control facilities, were approximately $55 million. In 2009, we estimate these expenditures to range between $35 and $50 million.

EMPLOYEES

We had 4,254 employees on December 31, 2008, of which 309 were employed under collective bargaining schemes. Information on our executive officers is presented in Item 10 of this report.

ITEM 1A.
Risk Factors

RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in the oil and gas industry and some of which are unique to our operations. Certain risks set out below constitute "forward-looking statements" and the reader should refer to the "Special Note Regarding Forward Looking Statements" set out on page 78 of this 10-K.

Our profitability and liquidity are highly dependent on the price of crude oil and natural gas.

Our operations and performance depend significantly on the price of crude oil and natural gas. Crude oil and natural gas are commodities which are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Historically, these prices have been very volatile, and are likely to remain volatile in the future. Current worldwide economic conditions have depressed crude oil and natural gas prices significantly, which may materially and adversely affect our results of operations and revenue generated from operating activities should those price levels persist for an extended period of time. The current price environment has also affected the value of our oil and gas properties and our level of spending for oil and gas exploration and development.

Our crude oil prices are based on various reference prices, which generally track the movement of Brent and WTI. Adjustments are made to the reference price to reflect quality differentials and transportation. Brent, WTI and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and geopolitical events.

The continued and unprecedented disruptions in the credit markets may negatively impact our liquidity.

While we generally rely upon cash flow from operations to fund our activities, a sustained depression in the prices of crude oil and natural gas may require us to draw upon existing credit facilities or issue new debt or equity to satisfy our funding needs. The current financial turmoil affecting the banking system and financial markets, and the possibility that financial institutions may consolidate or go out of business has resulted in a tightening of the credit markets, a low level of liquidity in many financial markets, and extreme volatility in fixed income, credit, currency and equity markets. There could be a number of follow-on effects from the credit crisis on our business which could negatively impact our liquidity and operations, and which may materially affect our business, including: a reduced ability to access credit or issue new public or private debt; higher costs of borrowing; lower returns on invested cash; and a negative change to our ratings outlook or even a reduction in our credit ratings by one or more credit rating agencies. A downgrade could limit our access to private and public credit markets and increase the costs of borrowing under existing facilities that could be available. If our credit ratings were downgraded, we could be required to provide additional liquidity to our marketing division if further collateral is required to be placed with counterparties, or reduce some of our marketing activities.

The inability of counterparties and joint operating partners to fulfill their obligations to us could adversely impact our results of operations.

Credit risk affects both our trading and non-trading activities and there is the risk of loss and additional burden if counterparties and joint venture partners do not or cannot fulfill their contractual obligations. In particular in 2008, the credit crisis that impacted world financial markets caused some of our counterparties to restructure, declare bankruptcy or sell assets to fund liquidity requirements. In 2009, we may experience similar developments. Most of our receivables and partners are with counterparties in the energy industry and are subject to normal industry credit risk. The inability of any one or more of these parties to fulfill their obligations to us may adversely impact our results of operations.

Competitive forces may limit our access to natural resources, and create labour and equipment shortages.

The oil and gas industry is highly competitive, particularly in the following areas:

- gaining access to areas or countries known to have available resources;
- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include national oil companies, major integrated oil and gas companies and various other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. The pulp and paper chemicals market is also highly competitive. Key success factors in each of these markets are price, product quality, logistics and reliability of supply.

Competitive forces may result in shortages of prospects to drill, labour, drilling rigs and other equipment to carry out exploration, development or operating activities, and shortages of infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could negatively impact our costs and prices and, therefore, our financial results.

We operate in harsh and unpredictable climates and locations where our access is regulated which could adversely impact our operations.

Some of our facilities are located in harsh and unpredictable climates and locations which can experience extreme weather conditions and natural disasters such as: sustained ambient temperatures above 40°C or below -35°C, flooding, droughts, wind and dust storms, difficult terrain, high seas, monsoons and hurricanes. These conditions are difficult to anticipate and cannot be controlled. In these conditions, operations can become difficult or unsafe and are often suspended. Some of our facilities and those upon which our facilities rely (such as pipelines, power, communications and oilfield equipment) are vulnerable to these types of extreme weather conditions and may suffer extensive damage as a result. If any such extreme weather were to occur, our ability to operate certain facilities and proceed with exploration or development programs could be seriously or completely impaired or destroyed, and could have a material adverse effect on our business, financial condition and results of operations. The insurance we maintain may not be adequate to cover our losses resulting from disasters or other business interruptions.

In some areas of the world, access and operations can only be conducted during limited times of the year due to weather or government regulation. These adverse conditions can limit our ability to operate in those areas and can intensify competition during periods of good weather for oil field equipment, services, and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs, and could have a material adverse effect on our business, financial condition and results of operations.

Exploration, development and production activities may not be successful and carry a risk of loss.

Acquiring, developing and exploring for oil and natural gas involves many risks. There is a risk that we will not encounter commercially productive oil or gas reservoirs, and that wells we drill may not be productive, or not sufficiently productive to recover all or any portion of our investment in those wells. Seismic data and other exploration technologies we use do not provide conclusive proof prior to drilling a well that crude oil or natural gas is present or may be produced economically. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- encountering unexpected formations or pressures;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- accidents and equipment failures;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

We may not achieve production targets should our reservoir production decline sooner than expected. Also, we operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. We may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may materially impact our operational activities and financial results.

Unconventional gas resource plays carry additional risks and uncertainties.

Part of Nexen's growth strategy is unconventional Canadian gas resource plays, such as CBM and shale gas. Exploitation techniques and practices for these resources in Canada generally remain in the early stages of development and it is very difficult to determine whether or not these resource plays will prove commercially viable, or to what degree.

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal. Some of the uncertainties associated with development of CBM resources are as follows:

- if the coalbed is water saturated, such as the Mannville coals in the Fort Assiniboine region of Alberta, water generally needs to be extracted to reduce the pressure and allow gas production to occur. A significant period of time may be required to dewater these wet coals and determine if commercial production is feasible. We may also have to invest significant capital in these assets before they achieve commercial rates of production, if ever;
- some coalbeds may not have sufficient natural permeability in the coalbed to recover the gas in place and can therefore require more extensive, and expensive, completion technologies which can increase the cost of drilling and production;
- the public may react negatively to certain water disposal practices related to water saturated CBM projects, even though these water disposal practices are regulated to ensure public safety and water conservation. Negative public perception around water saturated CBM production could impede our access to the resource;
- CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area; and
- regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

Shale gas is an unconventional gas produced from reservoirs composed of organic rich shales. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Some of the uncertainties associated with development of shale gas resources are as follows:

- shale gas wells typically have higher production decline rates, lower producing rates and reserves per well than conventional gas wells, although this varies by area;
- regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain; and
- shales are typically less permeable than conventional gas reservoirs, and can therefore require more extensive, and expensive, completion technologies which can increase the cost of drilling and production.

Our heavy oil production is more expensive and yields lower prices than light oil and gas.

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil making it more susceptible to supply and demand fundamentals which may cause the price to decline.

Any one or a combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

Without reserve additions, our reserves and production will decline over time and we require capital to produce remaining reserves.

Our future crude oil and natural gas reserves and production, and therefore our future operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, development or acquisitions, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves and production will be impaired.

Discovered oil and natural gas reserves are generally only produced when they are economically recoverable. As such, oil and gas prices, and capital and operating costs have an impact on whether reserves will ultimately be produced. As required by SEC rules, our proved reserves represent the quantities that we expect to economically recover using existing prices and costs at the end of the year. Proved reserves can increase or decrease under different price and cost scenarios. Our bitumen reserves are particularly sensitive to year-end prices and costs. Under current SEC rules, we are required to recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we produce from the Long Lake Project. We expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen reserves are sensitive to year-end prices. We recognize our oil sands as bitumen reserves and they are related to one project. All or none of the reserves will likely be considered economic depending on the year-end prices for bitumen, diluent and natural gas, even though the Long Lake Project has minimal exposure to these factors.

Our proved reserves include undeveloped properties that require additional capital to bring them on stream.

Under SEC rules, the definition of proved undeveloped reserves includes reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates. At December 31, 2008, 48% of our proved reserves before royalties (49% after royalties) were undeveloped. Refer to page 18 for information on our PUDs.

The Long Lake Project faces additional risks compared to conventional oil and gas production.

The Long Lake Project is a fully integrated production, upgrading and cogeneration facility. We use steam assisted gravity drainage (SAGD) technology to recover bitumen from oil sands. The bitumen is partially upgraded using the proprietary OrCrude™ process, followed by conventional hydrocracking to produce a sweet, premium synthetic crude oil. The OrCrude™ process also yields liquid asphaltenes that will be gasified into synthetic gas. This syngas is used as fuel for the SAGD process, a source of hydrogen in the upgrading process, and to generate electricity through a cogeneration facility.

We have a 65% working interest in this project. Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

In addition to the risks associated with heavy oil production stated above, risks associated with our Long Lake Project include the following:

Application of Relatively New SAGD Bitumen Recovery Process

SAGD has been used in western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade; however, application of SAGD to the insitu recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, although several commercial SAGD projects have been in steady state operation for over six years.

Our estimates for performance and recoverable volumes for the Long Lake Project are based primarily on our three well-pair SAGD pilot, the initial performance of our first commercial well phase, and industry performance from SAGD operations in like reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our assumptions included average well-pair productivity of 900 bbls/d of bitumen and a long-term steam-to-oil ratio of 3.0. While some of our wells have achieved these levels, there can be no certainty that our overall SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, purchase natural gas for additional steam generation, and/or make short-term bitumen purchases. These could have an adverse impact on the future activities and economic return of the Long Lake Project.

Application of New Bitumen Upgrading Process

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude is the first commercial application of the process although we have operated it in a 500 bbl/d demonstration plant and initial upgrader operations which began in January 2009 have produced the desired products. There can be no certainty that the commercial upgrader at Long Lake will sustain or achieve the results which are now being seen or forecast. If we are unable to continue to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading, which would expose us to the following risks:

- the market for bitumen is limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent which may cause its price to increase;
- the market price for bitumen is relatively low reflecting its quality differential;
- the market price for bitumen fluctuates over the course of the year; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake Project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from those we have assumed. This would materially decrease expected earnings from the project and the project may not be profitable under these conditions.

Dependence upon Proprietary Technology

The success of the project and our investment depends highly on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licensed by OPTI. OPTI currently relies on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licenses and patents, to secure the rights to utilize its proprietary technology and the proprietary technology of third parties. OPTI may have to engage in litigation to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of patents or proprietary rights of third parties. Litigation can be time-consuming and expensive, whether OPTI is successful or not. The process of seeking patent protection can itself be long and expensive, with no assurance that any pending or future patent applications of OPTI or such third parties will actually result in issued patents, or that, if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Others may develop technologies that are similar or superior to: 1) the technology of OPTI or third parties; or 2) the design around the patents owned by OPTI and/or third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for additional technologies required to possibly further expand the Long Lake upgrader.

Operational Hazards

The operation of the project is subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions, and our insurance may not sufficiently cover casualty occurrences or disruptions that occur. The project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. The project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher-value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit depend largely on production levels.

The Long Lake Project processes large volumes of hydrocarbons at high pressure and temperatures and will handle large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake Project produce sour gas, which is gas containing hydrogen sulphide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. The project includes integrated facilities for handling and treating the sour gas, including the use of gas sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shutdown of operations.

The Long Lake Project produces carbon dioxide emissions. Risk factors relating to environmental regulation are provided separately in this document.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Long Lake Project and on us.

Some of our production is concentrated in a few producing assets.

A significant portion of our production is generated from highly productive individual wells or central production facilities. Examples include:

- Scott and Buzzard production platforms in the North Sea;
- central processing facilities, oil pipelines, and export terminal at our Yemen operations;
- our Long Lake synthetic crude oil operations; and
- upgrading facilities at Syncrude in the Athabasca oil sands.

As significant production is generated from each asset, any single event that interrupts one of these operations could result in the loss of production.

Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our trading operations expose us to the risk of financial losses from various sources which may have a material and adverse effect on our financial performance. The commodity markets in which we trade have experienced unanticipated volatility relative to historical variances, resulting in unusual and significant pricing changes, and deviations from anticipated seasonal pricing trends and pricing levels. Our energy marketing division maintains a trading portfolio comprised of both long and short physical and financial positions which may be at any time significant in size or number, and which are predicated on a trading thesis for expected pricing levels and trends in forward or regional markets. Unanticipated volatility in the commodity price level and trends upon which those trading positions are based may cause those positions to decrease in value.

Significant changes in the commodities and financial markets could require us to provide additional liquidity if additional collateral is required to be placed with counterparties, or reduce some of our activities. Adverse credit-related events such as a downgrade of our credit rating to non-investment grade could require additional collateral to be placed with counterparties. Adverse credit-related events could also negatively affect trading counterparties who fail to fulfill their contractual obligations.

The transportation and storage assets and contracts owned by our energy marketing business may decrease in value due to changes in temporal and regional commodity pricing.

Use of marine transportation may expose us to the risk of financial loss and damaged reputation.

From time to time, we may choose to charter marine vessels for the transportation of crude oil. This may expose us to the risk of financial loss and damaged reputation in the event of oil spills.

We operate in countries with political, economic and security risks.

We operate in numerous countries, some of which may be considered politically and economically unstable. A portion of our revenue is derived from operations in these countries. As a result, our financial condition and operating results could be significantly affected by risks associated with international activities, including:

- civil unrest and general strikes;
- political instability, the risk of war and acts of terrorism;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- expropriation or forced renegotiation or modification of existing contracts;
- exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

The impact that future terrorist attacks or regional hostilities may have on the oil and gas industry in general, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities.

There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequence.

We may be affected by changes in government rules and regulations.

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we cannot predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. Changes in government regulations could adversely affect our results of operations and financial condition.

Increased environmental regulation could increase our operating costs.

The Kyoto Protocol came into force in 2005 and Canada ratified the Kyoto Protocol in December 2002. In 1997, Canada committed to an emission reduction of 6% below 1990 levels during the First Commitment period from 2008 to 2012. In 2007, the Canadian Federal government introduced a paper titled "Regulatory Framework for Air Emissions" which proposes that the Federal government regulate greenhouse gases (GHGs) and air pollutants beginning as early as 2010, with progressively more stringent reductions applied through 2050. GHGs are regulated based on CO_2 equivalent (CO_2e) intensity per unit of production until 2020–2025, when a cap and trade system may be imposed. The reduction obligations are contemplated

to be met through internal reductions, purchasing offsets or making payments into a technology fund (with escalating but defined costs). The purchasing of offsets was predicated on the establishment of a domestic emissions trading market. Offsets can be obtained from approved projects within Canada and from international projects approved by the Clean Development Mechanism Executive Board subject to certain limitations.

The Federal government was to publish proposed regulations in late 2008, however, no definitive regulation has been published to date. The Federal government's recent announcements indicating an interest in pursuing a bi-lateral cap and trade system with the United States have created further uncertainty about the implementation of their "Regulatory Framework for Air Emissions".

The Canadian Federal government has also indicated their intent to regulate air pollutants concurrent with GHGs but their schedule and long-term objectives remain unclear. We could face technical challenges in meeting some of the criteria for certain pollutants. Any required reductions in the GHGs emitted from our operations could result in increases in our capital or operating expense, or reduced operating rates, especially at the Long Lake Project, which could have an adverse effect on our results of operations and financial condition. As a "new facility" Long Lake will have three years to establish an emissions baseline before having a reduction obligation assigned. In 2008, our Canadian operations, including Syncrude, accounted for 25% of our production before royalties.

Alberta became the first jurisdiction in Canada to enact and implement binding emission reductions (a one time from base, 12% reduction in carbon intensity) on facilities emitting more than 100 kilo-tonnes of CO_2 equivalent. Facilities unable to achieve internal reductions have unlimited ability to pay into a technology fund at the rate of $15 per tonne of CO_2 equivalent. This amount must be paid annually until such time as internal reduction is achieved unless other approved offsets are acquired from projects in Alberta.

British Columbia enacted legislation in November 2007 entitled the *Greenhouse Gas Reduction Targets Act* which targets a 33% reduction in current provincial GHG emissions by 2020. Regulations affecting this reduction target have yet to be finalized and we are monitoring progress in that regard.

During the period 2010 to 2020, the Canadian carbon market could be short of supply leading to high carbon prices. It remains to be seen if the Federal and Alberta Provincial levels of government will harmonize their compliance regimes and how the revenue in the technology funds will be allocated.

Our three installations in the UK North Sea have allocations from the regulator and are part of the European Union Emission Trading System. The allocations cover emissions from combustion equipment and flaring from 2008 until 2012. Our installations are expected to have emissions in excess of allowances which will be covered by eligible offsets from the Clean Development Mechanism and purchases of EU Allowances.

Environmental liabilities inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations impose stringent controls on the manner in which we operate and our impact on the environment, and require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by disposing or releasing specified substances. Significant changes in the environmental laws and regulations governing our operations could have an adverse financial consequence on us.

Certain operations require the use of fresh and saline water which we currently obtain from both sub-surface and surface sources. Additional costs may be incurred if allocation limits are placed on our water usage, if our water needs exceed allocated amounts or if existing water allocations are reduced.

ITEM 1B.

Unresolved Staff Comments

There are no unresolved staff comments with the SEC.

ITEM 3.

Legal Proceedings

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect on our consolidated financial position or results of operations. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US Environmental Protection Agency (EPA), state environmental agencies, and certain third parties for certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands, and lawsuits have been received for certain sites related to historical operations and activities in the US for which, although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

ITEM 4.

Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2008.

PART II

ITEM 5.

Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY.

On December 31, 2008, there were 1,624 registered holders of common shares and 519,448,590 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings.

Issuer Purchases of Equity Securities during the Fourth Quarter [1]

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares (or units) purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares (or units) that may yet to be purchased under the plans or programs
October 1–31, 2008	1,093,900	$16.44	1,093,900	41,833,346
November 1–30, 2008	1,056,200	$18.92	1,056,200	40,777,146
December 1–31, 2008	–	–	–	40,777,146

1 *On July 30, 2008, we announced that Nexen received approval from the TSX for a Normal Course Issuer Bid that allows us to repurchase up to a maximum of 52,914,046 common shares in the period of August 6, 2008 to August 5, 2009.*

Trading Range of Nexen's Common Shares

($/share)	TSX (Cdn$) High	TSX (Cdn$) Low	NYSE (US$) High	NYSE (US$) Low
2008				
First Quarter	34.20	26.00	34.57	25.11
Second Quarter	43.45	29.69	42.71	28.87
Third Quarter	41.47	21.12	40.99	20.56
Fourth Quarter	29.10	13.33	23.99	10.81
2007				
First Quarter	37.60	29.66	31.88	25.18
Second Quarter	36.51	31.25	32.21	29.08
Third Quarter	36.32	27.21	34.79	25.25
Fourth Quarter	32.63	27.88	34.37	27.58

Quarterly Dividends Declared on Common Shares

($/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008	0.025	0.050	0.050	0.050
2007	0.025	0.025	0.025	0.025

Payment date for dividends was the first day of the next quarter. All dividends paid to holders of common shares in 2008 have been designated as "eligible dividends" for Canadian tax purposes. This designation will apply to all such dividends paid in the future unless otherwise notified by us.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian", as defined, file notice with Investment Canada and obtain government approval prior to acquiring control of a Canadian business, as defined. Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities (refer to the table of securities authorized for issuance under equity compensation plans on page 161).

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. According to the Plan, a right is attached to each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares, and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our board can defer the separation date.

Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2011 to remain effective past that date. A copy of the Plan is available on our web site at www.nexeninc.com.

ITEM 6.

Selected Financial Data

Five-Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn$ millions, except otherwise indicated)	2008	2007	2006	2005	2004
Oil & Gas and Syncrude Production					
Production Before Royalties (mboe/d)[1]	250	254	212	242	250
Production After Royalties (mboe/d)[1]	210	207	156	173	174
Results of Operations					
Revenue					
Oil & Gas and Syncrude[2]	6,907	5,174	3,656	3,535	2,573
Marketing	522	926	1,373	864	625
Chemicals	427	447	413	413	383
Other	364	(26)	(47)	(193)	59
Total Revenue	8,220	6,521	5,395	4,619	3,640
Net Income from Continuing Operations	1,704	1,012	579	658	705
Basic Earnings per Common Share from Continuing Operations ($/share)	3.24	1.92	1.10	1.26	1.37
Diluted Earnings per Common Share from Continuing Operations ($/share)	3.20	1.88	1.08	1.23	1.35
Net Income	1,704	1,012	579	1,110	788
Basic Earnings per Common Share ($/share)	3.24	1.92	1.10	2.13	1.53
Diluted Earnings per Common Share ($/share)	3.20	1.88	1.08	2.08	1.51
Financial Position					
Total Assets[1]	22,048	17,982	17,079	14,493	12,339
Long-Term Debt[3]	6,578	4,610	4,618	3,630	4,214
Shareholders' Equity	6,946	5,449	4,614	3,961	2,892
Capital Investment, including Acquisitions	3,066	3,401	3,408	2,638	4,264
Dividends per Common Share ($/share)[4]	0.175	0.10	0.10	0.10	0.10
Common Shares Outstanding (thousands)[5]	519,449	528,305	525,026	522,281	516,798

1 *In late 2004, we acquired North Sea assets and began production from Block 51 in Yemen. In 2005, we sold producing properties in Canada and suffered hurricane-related downtime in the Gulf of Mexico. A full year's production from the North Sea and Block 51 in Yemen offset declines caused by these events. In early 2007, the Buzzard field came on stream and offset declines from Masila in Yemen.*

2 *In the third quarter of 2005, we sold Canadian conventional oil and gas properties in Saskatchewan, British Columbia and Alberta producing 18,300 bbls/d. The results of these operations have been shown as discontinued operations.*

3 *In December 2004, we drew US$1.5 billion on unsecured acquisition credit facilities to finance the purchase of North Sea assets. The remainder of the purchase price was funded from cash on hand. The acquisition credit facility was repaid in 2005 with proceeds from the issuance of US$1.04 billion in senior notes in the first quarter and from asset dispositions in the third quarter. Our long-term debt increased in 2006 as a result of our capital investments, primarily at Buzzard and Long Lake. In May 2007, we issued US$1.5 billion of senior notes with US$250 million maturing in 10 years and US$1,250 million maturing in 30 years. In June 2007, we filed a universal base shelf prospectus in the US and Canada allowing us to potentially raise US$2.5 billion of debt, equity or other hybrid securities, should the need arise.*

4 *Quarterly dividends were increased to 5¢ per share in the second quarter of 2008.*

5 *During the third quarter of 2008, we received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid that allows us to repurchase up to a maximum of 52,914,046 common shares for the period of August 6, 2008 to August 5, 2009. In 2008, we repurchased and cancelled 12,136,900 common shares for $338 million.*

MANAGEMENT'S DISCUSSION AND ANALYSIS

Despite economic volatility,
2008 had record results reflecting strong
oil prices and solid netbacks.

PART II

ITEM 7.
Management's Discussion and Analysis of Financial Condition and Results of Operations

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 23 to the Consolidated Financial Statements. The date of this discussion is February 11, 2009. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities include our Syncrude activities since the product produced from Syncrude competes in the oil and gas market. Oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

1 *Investors should read the Special Note Regarding Forward-Looking Statements on page 78.*
2 *Canadian investors should read the Special Note to Canadian Investors on page 79 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.*

ITEM 7A.

EXECUTIVE SUMMARY

2008 Results

(Cdn$ millions)	2008	2007	2006
Production before Royalties (mboe/d)[1]	250	254	212
Production after Royalties (mboe/d)	210	207	156
Cash Flow from Operating Activities	4,354	2,830	2,374
Net Income	1,715	1,086	601
Earnings per Common Share, Basic ($/share)	3.26	2.06	1.15
Net Debt[2]	4,575	4,404	4,730

1 Production before royalties reflects our working interest before royalties and includes production of synthetic crude oil from Syncrude. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

2 Long-term debt and short-term borrowings less cash and cash equivalents.

Production before royalties averaged 250,000 boe/d in 2008, slightly below last year's volumes. Higher rates at Buzzard were offset by declines at our maturing Yemen properties and hurricane interruptions in the Gulf of Mexico. Buzzard continues to operate reliably and production in 2008 averaged 204,200 boe/d (88,200 net to us). We expect our consolidated production rates will increase in 2009 primarily as a result of new volumes from our Long Lake Project, Ettrick in the UK North Sea and Longhorn in the Gulf of Mexico.

We achieved record financial results in 2008, generating cash flow from operating activities in excess of $4 billion and net income of $1.7 billion. Commodity prices reached new highs during the year, but fell in the fourth quarter as a result of the global economic crisis. WTI crude oil averaged US$99.65/bbl for the year, 38% higher than last year. Despite the fall in crude oil and gas prices in the last part of the year, the strengthening US dollar kept our price realizations strong.

Much of our production has low operating costs and low royalties. Our cash netbacks continue to be among the highest in the industry, averaging $72.97/boe after royalties for the year. High netbacks deliver superior relative performance even as commodity prices decline.

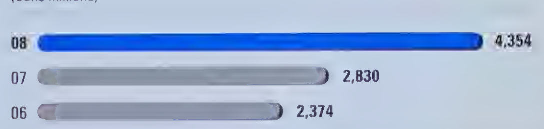
The past year proved challenging for our energy marketing group as unprecedented market conditions impacted physical market fundamentals and the pricing relationships we successfully positioned ourselves to profit from historically. While the global economic slowdown produced challenges for our business, the marketing team was most impacted by significant swings in commodity markets. We were positioned to take advantage of normal market fundamentals but these were overwhelmed by significant price movements, increased volatility and the economic slowdown. Since the middle of the year, we have been refocusing this division and reducing the size of our trading levels. In response to the rapidly deteriorating economic environment and financial markets, we were carefully choosing our exit points. With the gas trading positions we recently exited, the refocusing of our gas marketing business back to physical transportation and storage is now complete.

Our net income includes impairment expense of $568 million (before tax) related to properties in the UK North Sea and the Gulf of Mexico. These properties were impaired by lower commodity prices, lower reserve estimates and unexpected costs.

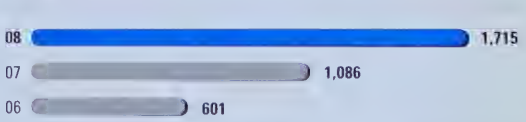
We reduced our net debt by approximately $1.3 billion with cash flow that exceeded our capital investment. This was offset by the impact of a stronger US dollar which increased our US-dollar denominated debt by $1 billion at year end, and by repurchasing 12 million common shares for approximately $340 million.

Our financial position is strong. We have financial flexibility with major capital projects complete at Buzzard and Long Lake, and industry-leading cash netbacks. We have liquidity of approximately $3.5 billion after acquiring the additional Long Lake interest in January 2009, comprised of cash on hand and undrawn committed credit. We have no debt maturities until 2011 and the average term-to-maturity of our long-term debt is approximately 18 years.

CASH FLOW FROM OPERATING ACTIVITIES
(Cdn$ millions)



NET INCOME
(Cdn$ millions)



Strategy Progress

(Cdn$ millions)	2008	2007	2006
Capital Investment, including Acquisitions	3,066	3,401	3,408
Proved Oil and Gas Reserves before Royalties (mmboe)[1]	664	734	725
Proved Oil and Gas Reserves after Royalties (mmboe)[1]	631	650	637
Proved Syncrude Reserves before Royalties (mmboe)[1]	324	324	324
Proved Syncrude Reserves after Royalties (mmboe)[1]	295	267	274

1 Includes developed and undeveloped proved reserves as at December 31.

Our strategy is to build a sustainable energy company focused in three areas: oil sands, unconventional gas and select conventional exploration and exploitation. Our investment in these areas generated the following results in 2008:

- Oil Sands—the Long Lake Project began producing bitumen and we completed construction and commissioning of the upgrader. First production of premium synthetic crude from the upgrader began in January 2009. We continued to focus on our oil sands growth strategy by increasing our interest in Long Lake by 15% to 65% in early 2009.
- Unconventional Gas—we have a significant land position in the Horn River basin in northeast British Columbia and started to test the area with exploration drilling and fracing activities. We continued to explore and develop CBM opportunities in Canada.
- Select Conventional Exploration and Exploitation—our conventional exploration program was focused in the US Gulf of Mexico and the UK North Sea, which yielded four discoveries that provide opportunities for future growth.

During 2008, our proved oil and gas and Syncrude reserves additions replaced 25% of our oil and gas and Syncrude production (112% after royalties). Excluding economic revisions, we replaced 79% of our oil and gas and Syncrude production (86% after royalties). The difference between before and after royalties reflects a reduction in the royalties on oil sands activities where the royalty rate is sensitive to prices.

Before Royalties

(mmboe)	Oil and Gas	Syncrude	Total
Production	**86**	**8**	**94**
Reserve Changes excluding Production			
Net Additions	66	8	74
Economic Revisions	(50)	–	(50)
	16	**8**	**24**

After Royalties

(mmboe)	Oil and Gas	Syncrude	Total
Production	**72**	**7**	**79**
Reserve Changes excluding Production			
Net Additions	60	7	67
Economic Revisions	(7)	28	21
	53	**35**	**88**

The majority of our additions before economic revisions relate to activities at Buzzard, Long Lake, Masila and Canadian CBM. Negative revisions occurred at Ettrick as a result of disappointing drilling and testing results which caused us to reduce our expectations of recoverable reserves. Additional information on our proved oil and gas and Syncrude reserves can be found in Items 1 and 2 Business and Properties (pages 15 to 20) and in Item 8 Financial Statements and Supplementary Data (pages 126 to 131).

Outlook

In 2009, we expect production to grow approximately 5% to 10% compared to 2008 and range between 255,000 and 270,000 boe/d before royalties. On an after-royalties basis, we expect production to grow 7% to 14% and range between 225,000 and 240,000 boe/d, reflecting growth in the UK North Sea and at Long Lake where royalties are low. Increases are expected to come from Ettrick in the UK North Sea, Longhorn in the US Gulf of Mexico and the Long Lake Project as bitumen rates ramp up.

Our capital investment plans for 2009 total $2.8 billion. We plan to finance this investment through cash flow from operating activities and existing cash and cash equivalents. The primary focus of our investment will be on our major and core asset developments at Buzzard and Ettrick in the North Sea, Longhorn in the Gulf of Mexico, and Usan, offshore Nigeria. We also plan to spend approximately $700 million advancing our new growth exploration and appraisal opportunities including our Horn River shale gas play. We are monitoring our capital spending throughout the upcoming year and are prepared to reduce our capital budget in response to the economic environment.

Our large capital projects at Buzzard and Long Lake Phase 1 are behind us and at year end, we had over $2 billion of cash on hand, $2.5 billion of undrawn committed credit facilities that are available until 2012 and $613 million in uncommitted credit facilities. We used existing term credit facilities and cash on hand early in 2009 to increase our interest in the Long Lake Project by 15%. We have no debt maturities over the next few years and believe we will continue to have substantial liquidity that provides us with the financial strength and flexibility to weather low commodity prices during this uncertain time. The average term-to-maturity of our debt is approximately 18 years.

CAPITAL INVESTMENT

(Cdn$ millions)	**Estimated 2009**	**2008**	**2007**
Major Development	780	1,437	1,479
Early Stage Development	210	167	162
New Growth Exploration	690	582	573
Core Asset Development	880	731	1,069
Total Oil & Gas and Syncrude	2,560	2,917	3,283
Energy Marketing, Corporate, Chemicals and Other	270	149	118
Total Capital	**2,830**	**3,066**	**3,401**

Our strategy and capital programs are focused on growing long-term value for our shareholders responsibly. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- exploration and new growth projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning toward less mature basins and unconventional resource plays. Key focus areas include the North Sea, Athabasca oil sands, Canadian CBM and shale gas, deep-water Gulf of Mexico, offshore West Africa and the Middle East—areas we believe have attractive fiscal terms, significant remaining opportunity, and where we have a competitive advantage.

2008 Capital

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	847	156	2	20	1,025
United States	87	–	154	164	405
United Kingdom	263	–	146	282	691
Canada	63	11	223	105	402
Yemen	–	–	9	92	101
Nigeria	177	–	3	–	180
Other Countries	–	–	45	13	58
Syncrude	–	–	–	55	55
	1,437	**167**	**582**	**731**	**2,917**
Chemicals	–	–	–	88	88
Energy Marketing, Corporate and Other	–	–	–	61	61
Total Capital	**1,437**	**167**	**582**	**880**	**3,066**
As a % of Total Capital	47%	5%	19%	29%	100%

2009 Estimated Capital

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	–	180	–	110	290
United States	105	10	190	60	365
United Kingdom	160	10	175	400	745
Canada	–	10	180	90	280
Yemen	–	–	–	120	120
Nigeria	515	–	25	–	540
Other Countries	–	–	120	10	130
Syncrude	–	–	–	90	90
	780	**210**	**690**	**880**	**2,560**
Chemicals	–	–	–	194	194
Energy Marketing, Corporate and Other	–	–	–	76	76
Total Capital	**780**	**210**	**690**	**1,150**	**2,830**
As a % of Total Capital	28%	7%	24%	41%	100%

Synthetic

In 2008, we invested $1 billion to develop our insitu oil sands resource. This included an investment of approximately $847 million on the first phase of Long Lake, $425 million of which related to the upgrader. The remaining expenditures related to preliminary work for future phases of Long Lake. At Long Lake, we added 19 mmboe of proved bitumen reserves based on further core-hole delineation of the lease.

In late January 2009, we completed the $735 million acquisition of an additional 15% interest in the Long Lake Project and the joint venture lands from OPTI Canada Ltd. We now own 65% of the Long Lake Project and joint venture lands. As part of the transaction, we assumed operatorship of the upgrader from OPTI, and are now the sole operator of the Long Lake Project. We expect this will create operational efficiencies and reduce the cost of managing Long Lake. With the completion of this acquisition, our total company proved reserves have increased by approximately 9%. These additions will be booked in 2009.

We recently reached a significant milestone at Long Lake when we produced first premium synthetic crude (PSC™) from the upgrader. The main process units of the upgrader have been successfully started up and are operating. Synthetic natural gas (Syngas) from the upgrader is being used in SAGD operations and this has significantly reduced the need for purchased natural gas. Currently, we are producing between 10,000 and 15,000 bbls/d gross of upgraded on-spec product. The upgrader is expected to ramp up to full design rates of approximately 60,000 bbls/d (39,000 bbls/d net to us) over the next 12 to 18 months. As the upgrader ramps up to full capacity, we expect that there will be periods of downtime as we work through the

early stages of production. This periodic downtime is normal and consistent with industry experience.

Bitumen production from the reservoir is performing well but our overall ramp up of production has been affected by a variety of surface issues that have limited the amount of steam injected into the reservoir over the past few months. Since steam injection rates directly impact bitumen production rates, when our ability to generate steam is limited, our bitumen production is lower. Most recently, our SAGD production was reduced as a result of power disruptions, extreme cold weather and water treating issues. As the weather improves and we recover from power disruptions and water treatment issues, our production rates have increased. We are currently producing approximately 20,000 bbls/d (gross) of bitumen, the highest we have seen to date. Due to steaming constraints, we have been forced to allocate our steam injection and accordingly we have 32 of the 81 well pairs on production. On average, these well pairs are producing at approximately 75% of their design rates after 11 months of SAGD operation. This is consistent with expectations as we expected a ramp up period of 12 to 18 months. The average steam-to-oil ratio (SOR) for these wells is currently less than 4.0. As we increase our steam capacity, we will bring on all remaining wells.

Phase 1 of Long Lake will develop approximately 10% of our oil sands inventory. The sanctioning of Phase 2 will depend on multiple factors including the initial performance of Phase 1, receiving regulatory approval for Phase 2 SAGD operations, receiving clarity on proposed climate change regulations, finalizing cost estimates and an improved economic environment. We therefore do not expect to sanction Phase 2 until mid 2010 at the earliest. In 2009, we plan to advance detailed engineering on the SAGD and upgrader facilities for Phase 2 of Long Lake and conduct core hole drilling to further delineate our leases.

United States

Development of Longhorn continues to progress with first production expected in mid 2009. This development comprises four subsea wells tied in to the ENI-operated Corral Platform, previously known as the Crystal Platform. We expect peak production rates in excess of 200 mmcf/d gross (50 mmcf/d net to us) by year end. In 2008, we invested $87 million developing Longhorn. We have a 25% non-operated working interest in Longhorn and ENI is the operator.

In 2008, our exploration program primarily focused on the deep water. In the eastern Gulf of Mexico, we drilled the Fredericksburg exploration well. Target sands were reached but we did not encounter commercial hydrocarbons. This was the third prospect to be drilled in the area following earlier successes at Vicksburg and Shiloh. We remain optimistic about the potential of this emerging play and expect to drill up to two exploration wells and one appraisal well in the area in 2009. In addition, we have a feasibility study underway to assess development options for the Vicksburg discovery. We have a 25% interest in Vicksburg and a 20% interest in Shiloh with Shell operating both.

At our Cote de Mer prospect, located on the Louisiana coast, exploratory drilling was interrupted by hurricanes Gustav and Ike. Following successful pipe recovery operations, the well was sidetracked to a depth of 21,700 feet, and penetrated the target zone. We continue to be encouraged by the logging data received to date, and are attempting to drill the remaining 600 feet of the target interval. We have a 37.5% working interest in this prospect.

In 2008, we invested $164 million to add production volumes from the Green Canyon 6 area and to recomplete wells on our producing properties.

United Kingdom

We invested almost $700 million in the UK last year. This included approximately $250 million at Buzzard and added proved reserves of 29 mmboe (29 after royalties). Successful drilling and production performance resulted in increases in both reservoir size and overall recovery factor which led to these proved reserve adds. These additions were offset by negative economic revisions of 10 mmboe (10 after royalties) due to low year-end prices.

In 2009, Buzzard will continue to be a significant contributor to our cash flow and production volumes. Throughout the year, we will continue construction of the fourth platform containing production sweetening facilities designed to handle higher levels of hydrogen sulphide. During the third quarter, we plan to install the jackets for this platform and complete tie-in operations, pending installation of the topsides. This will result in about one month of downtime which coincides with a six week planned slowdown of the Forties pipeline.

Our Ettrick development in the North Sea is progressing towards first oil in the next few months. In 2008, we invested approximately $260 million. During 2008, we had 12 mmboe of negative reserve revisions (12 after royalties), of which approximately one quarter relate to lower oil prices. The remaining revisions are due to disappointing drilling results that lowered our reserve estimates. The Ettrick development consists of a leased floating production, storage and offloading vessel (FPSO) designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas. We expect Ettrick to add approximately 10,000 boe/d to our 2009 production volumes. We also have a discovery at Blackbird which could be a future tie-back to Ettrick. We have no proven reserves booked for Blackbird. In 2009, we plan to drill an appraisal well to further evaluate this discovery. We operate both Ettrick and Blackbird, with an 80% working interest in each.

We recently drilled a successful appraisal well at Rochelle on Block 15/27 in the North Sea. The well was tested and flowed at an average restricted rate of 41 mmcf/d of gas and 2,300 bbls/d of oil condensate. We are evaluating future appraisal and fast-track development options and have a 44% non-operated working interest in the well.

Elsewhere, we are assessing future appraisal and development alternatives for the growing Golden Eagle area. This area includes discoveries at Golden Eagle, Pink and most recently, Hobby, where we are encouraged by early results. We are planning to drill multiple sidetracks to determine the extent of both Hobby and Golden Eagle. Hobby is located on Block 20/1N approximately 1.5 km west of the Golden Eagle discovery. We have a 34% interest in both Hobby and Golden Eagle, a 46% interest in Pink, and operate all three. We have identified additional prospects in the area and have plans for further exploratory and appraisal drilling this year.

Canada

As conventional basins in Canada mature, we are focusing our investment on unconventional resource plays such as shale gas and CBM. In northeast British Columbia, we have a material land position of approximately 126,000 acres with a 100% working interest in an emerging Devonian shale gas play. This play has the potential to be one of the most significant shale gas plays in North America. Our landholdings include approximately 88,000 acres in the Dilly Creek area of the Horn River basin. In 2008, we invested approximately $180 million to drill, complete and test wells, and build infrastructure. One horizontal well was completed and tied in last winter and is producing at rates in line with our expectations and competitor wells. We expect to complete and tie-in two wells later this winter. We continue to construct all season roads to provide year-round access to our lands. In 2009, we plan to enhance our understanding of drilling and fracing techniques for this play with an investment plan that includes drilling and testing multiple wells from a single pad. We expect three of these wells to be drilled and completed by mid-year and on production before winter. The remaining wells will be drilled in the future if economic and financial conditions improve. Further appraisal activity is required before we can finalize estimates, establish commerciality and book proved reserves.

In 2008, we invested approximately $115 million in exploration and development activities on our CBM lands and recognized 10 mmboe of proved reserves (10 after royalties). We expect our CBM reserves to grow over the coming years as additional wells are drilled, development work progresses and more production history is obtained. Our CBM production continues to increase as existing wells de-water and we bring new wells on stream. In 2008, our production increased 65% and we exited the year producing approximately 50 mmcf/d. Performance is in line with expectations and underscores the increasing value of our CBM assets.

2008 CAPITAL

1 Mainly Long Lake.
2 Energy Marketing, Corporate and Other.

2009 ESTIMATED CAPITAL

1 Mainly Long Lake but excludes acquisition of additional 15% in Long Lake project and joint venture lands.
2 Energy Marketing, Corporate and Other.

Elsewhere in Canada, we increased our proved reserves by 3 mmboe (3 after royalties), but these additions were offset by negative economic revisions of 27 mmboe (22 after royalties) largely relating to our conventional heavy oil properties. These economic revisions were determined in accordance with current SEC rules that require the use of year-end commodity prices and operating costs even though we believe year-end operating costs do not reflect the current economic downturn and low commodity price environment.

Yemen

Yemen remains a significant asset for us and continues to generate cash flow in excess of capital requirements. In 2008, we invested $101 million and added 12 mmboe (9 after royalties) of proved reserves. We will continue to maximize the value of these assets over their remaining contract terms and expect 2009 annual production of between 40,000 and 45,000 boe/d, before royalties.

Other Countries

Development of the Usan field, offshore West Africa, is underway with first production expected in 2012. In 2008, our capital investment at Usan on block OML-138 focused on detailed engineering, procurement and the initial fabrication of equipment. The development of Usan includes an FPSO with the ability to process 180,000 bbls/d and store up to two million barrels of oil. In 2009, we are scheduled to begin fabrication of the FPSO hull and topside facilities, begin development drilling, and complete detailed engineering and procurement. We are also evaluating plans for further exploration on this block. We have a 20% interest in exploration and development along with Total E&P Nigeria Limited (20% and Operator), Chevron Petroleum Nigeria Limited (30%) and Esso Exploration and Production Nigeria (Offshore East) Limited (30%).

In the fourth quarter of 2008, Nigerian authorities approved the acquisition of interests in offshore block OPL-223. We have a 20% funding interest and 18% beneficial interest in this block. Our partners are Total E&P Nigeria Limited (18% and Operator) ChevronTexaco Nigeria Deepwater F Limited (27%), Esso Exploration and Production (Upstream) Limited (27%) and Nigerian Petroleum Development Company Limited (10% carried interest). During 2009, we plan to advance evaluation of the prospects on this block.

Other international includes our producing assets in Colombia and our exploration program in the Norwegian North Sea. In 2008, we invested approximately $95 million in Norway, primarily to acquire seismic data.

Syncrude

At Syncrude, we invested $55 million in 2008 and added 8 mmboe (7 after royalties) of proved reserves. In 2009, we have one coker turnaround scheduled in the second quarter and expect annual production of between 20,000 and 25,000 bbls/d before royalties.

Chemicals

Higher expenditures in 2008 related to the technology conversion project at our North Vancouver chlor-alkali plant. This was offset by lower expenditures related to the expansion of our Brandon sodium chlorate plant, which was completed in early 2008.

FINANCIAL RESULTS

Year-to-Year Change in Net Income

(Cdn$ millions)	2008 vs 2007	2007 vs 2006
Net Income for 2007 and 2006	**1,086**	**601**
Favourable (unfavourable) variances:[1]		
Production Volumes, After Royalties		
Crude Oil	40	1,354
Natural Gas	(22)	(17)
Change in Crude Oil Inventory	13	22
Total Volume Variance	31	1,359
Realized Commodity Prices		
Crude Oil	1,495	308
Natural Gas	119	(24)
Total Price Variance	1,614	284
Operating Expense		
Conventional Oil & Gas	(49)	(178)
Syncrude	(72)	(21)
Total Operating Expense Variance	(121)	(199)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas and Syncrude	(228)	(636)
Other	(19)	(7)
Total DD&A	(247)	(643)
Exploration Expense	(76)	36
Net Energy Marketing Revenue	(424)	(373)
Chemicals Contribution	(76)	27
General and Administrative Expense	117	181
Interest Expense	74	(115)
Current Income Taxes	(425)	(66)
Future Income Taxes	(240)	(43)
Other		
Block 51 Settlement	–	151
Business Interruption Insurance Proceeds	–	(154)
Increase (Decrease) in Fair Value of Crude Oil Put Options	246	(32)
Other	156	72
Net Income for 2008 and 2007	**1,715**	**1,086**

1 *All amounts are presented before provision for income taxes.*

Significant variances in net income are explained in the sections that follow.

OIL & GAS AND SYNCRUDE

Production

	2008		2007		2006	
	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties
Oil and Liquids (mbbls/d)						
United Kingdom	99.7	99.7	81.2	81.2	16.9	16.9
Yemen	56.6	30.6	71.6	39.8	92.9	51.8
Canada	16.2	12.3	17.1	13.4	20.0	15.8
United States	9.3	8.1	16.4	14.5	17.0	15.0
Other Countries	5.8	5.3	6.2	5.7	6.3	5.7
Long Lake Bitumen[2]	3.9	3.9	–	–	–	–
Syncrude (mbbls/d)[3]	20.9	18.2	22.1	18.8	18.7	16.9
	212.4	178.1	214.6	173.4	171.8	122.1
Natural Gas (mmcf/d)						
United Kingdom	18	18	16	16	20	20
Canada	131	109	118	98	108	91
United States	78	66	101	86	111	94
	227	193	235	200	239	205
Total (mboe/d)	**250**	**210**	**254**	**207**	**212**	**156**

1 We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.
2 Pre-operating revenues and costs associated with Long Lake bitumen are capitalized as development costs until we reach commercial operations.
3 Considered a mining operation for US reporting purposes.

2008 vs 2007—Higher net production increased income by $31 million

Production after royalties in 2008 was slightly higher than 2007. At Buzzard, a full year of production offset declines at our maturing Yemen fields and hurricane interruptions in the US Gulf of Mexico. At Long Lake, increasing bitumen production contributed 3,900 boe/d to our 2008 volumes.

The following table summarizes our production changes year-over-year:

(mboe/d)	Before Royalties	After Royalties
2007 Production	254	207
Production Changes		
United Kingdom	19	19
Yemen	(15)	(9)
United States	(11)	(10)
Long Lake Bitumen	4	4
Other	(1)	(1)
2008 Production	**250**	**210**

Fourth quarter production averaged 230,000 boe/d (198,000 after royalties), down 16,000 boe/d from the prior quarter and 11,000 boe/d from the fourth quarter of 2007. Shut-in production in the Gulf of Mexico was the primary cause for the shortfall as US rates averaged 9,000 boe/d during the fourth quarter. The US was producing approximately 30,000 boe/d prior to the hurricanes. These shortfalls were partially offset by production at Long Lake where we averaged 6,500 boe/d for the quarter.

In 2009, we expect production to grow approximately 5% to 10% compared to 2008 and range between 255,000 and 270,000 boe/d before royalties. On an after-royalties basis, we expect production to grow 7% to 14% and range between 225,000 and 240,000 boe/d, reflecting growth in the UK North Sea and at Long Lake where royalties are low. Increases are expected to come from Ettrick in the UK North Sea, Longhorn in the US Gulf of Mexico and the Long Lake Project as bitumen rates increase.

Production volumes discussed in this section represent our working interest before royalties.

United Kingdom

UK production for the year averaged 102,700 boe/d, 22% higher than 2007. This increase was primarily the result of a full year's high-margin, royalty-free Buzzard production, which averaged 88,200 boe/d. The Buzzard platform operated above expectations with minimal downtime. We are pursuing debottlenecking opportunities to increase processing capacity on the platform and export facilities.

Construction of the fourth platform at Buzzard started during the year. This platform will include production sweetening facilities designed to handle higher levels of hydrogen sulphide previously identified in the reservoir. The platform is expected to be in service in 2010 at a projected cost of between US$350 million and US$400 million, net to us.

At Scott/Telford, higher than expected natural declines, combined with increased downtime for maintenance, reduced production by 36% to 10,500 boe/d. Maintenance on the Scott platform focused on resolving ongoing power supply issues. Downtime was also associated with platform and subsea workovers completed during the year. We recently started an infill drilling program at Scott to minimize the natural declines.

In 2009, we plan to drill up to three development wells at Scott/Telford and we anticipate bringing production on stream at Ettrick in the next few months. We expect production from the North Sea to average between 100,000 and 115,000 boe/d in 2009. Our expected production for 2009 takes into account expected downtime.

Yemen

In 2008, production from our Masila field declined 19% compared to last year and averaged 45,900 boe/d. This decline is consistent with our expectations as the field matures. We are targeting select infill development drilling opportunities due to the maturity of the field. During the year, we drilled 20 development wells and two sidetrack wells as we concentrate our drilling program on maximizing reserve recoveries and economic returns, prior to the 2011 expiry of our contract. In 2009, we plan to drill up to 35 development wells.

Production at our East Al Hajr field on Block 51 averaged 10,700 boe/d for 2008 and reflects natural declines and drilling fewer development wells. We drilled six development wells and one exploration well this year and plan to drill up to five development wells in 2009. We expect our share of Yemen production to average between 40,000 and 45,000 boe/d in 2009.

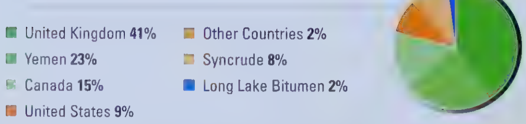
Canada

Production in Canada (excluding oil sands) increased 3% in 2008, primarily as a result of increasing CBM volumes, offset by a decline in heavy oil production. CBM production increased 65% to average 43 mmcf/d during the year as we brought additional wells and facilities on stream and as existing wells in our Fort Assiniboine development inclined as they de-watered. Production from our heavy oil properties fell 7% in 2008. A successful capital investment program slowed declines in our maturing fields. Our natural gas production in the Medicine Hat region and at Balzac was comparable with the previous year.

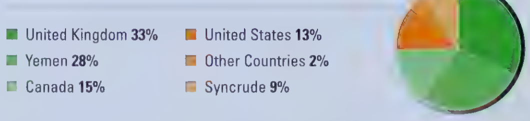
Bitumen production at Long Lake averaged 3,900 boe/d (net to us) during 2008. We continued to inject steam into the reservoir and resolved a number of start-up issues with the SAGD operations during the year. The upgrader began producing premium synthetic crude oil in January 2009. The project is upgrading bitumen from our SAGD production and third-party bitumen purchases, and is currently producing between 10,000 and 15,000 boe/d of premium synthetic crude (between 6,300 and 9,750 net to us). Our SAGD operations and the upgrader start-up were impacted by normal start-up challenges and extraordinarily cold weather. As a result, bitumen production averaged 13,200 boe/d for the fourth quarter (6,600 net to us), although rates are back up to 20,000 boe/d (13,000 net to us) in late January 2009. In early 2009, we increased our interest in the Long Lake Project from 50% to 65%.

In 2009, we expect our share of production from Canada to average between 35,000 and 40,000 boe/d and bitumen SAGD production at Long Lake is expected to average between 20,000 and 25,000 boe/d (net to us).

2008 PRODUCTION BEFORE ROYALTIES



2007 PRODUCTION BEFORE ROYALTIES



United States

Our US production fell 33%, or about 11,000 boe/d from 2007, as hurricanes in the Gulf of Mexico temporarily shut-in production in the region. Prior to Hurricanes Gustav and Ike, we were producing approximately 30,000 boe/d. Production was reduced to 6,000 boe/d immediately after the hurricanes. Our properties at Gunnison, West Cameron and Eugene Island came back on stream during the fourth quarter and we exited the year producing approximately 12,000 boe/d. Production at Aspen recommenced at the end of January 2009. Wrigley remains shut in as third-party facilities have not yet been fully repaired. This work is ongoing and we expect production will be restored to pre-hurricane rates in the first quarter of 2009. Our Green Canyon 6, 50 and 137 deep-water fields remain shut in following the destruction of the third-party processing platform. We are currently evaluating production options for these fields.

Prior to the hurricanes, Aspen was producing 5,000 boe/d, down 50% from 2007. The decline is a result of: (i) natural decline rates; (ii) increased downtime due to third-party facility maintenance; and (iii) third-party limitations on handling higher water volumes. Production was curtailed while increased water handling equipment was installed on the Shell-operated platform. We expect production rates from Aspen to increase slightly in 2009 as the platform can now handle additional amounts of water from the field.

Gunnison suffered only minor damage during the storms and was back on stream in October. Pre-hurricane Gunnison production averaged 5,000 boe/d, down 26% from 2007. Lower volumes due to natural declines and ongoing maintenance were partially offset by an additional development well drilled during the year and successful recompletions.

Our shelf production decreased 3,800 boe/d as a result of natural declines, approximately 27% below 2007 rates. During the year, we completed several successful recompletions and workovers to enhance performance; however, we are minimizing the capital invested in our mature shelf assets.

In 2009, we expect production from the Gulf of Mexico to average between 20,000 and 25,000 boe/d.

Other Countries

Production from Guando in Colombia decreased marginally to 5,800 boe/d in 2008. The infill drilling program was completed in the second quarter of 2008; however, the full benefit of this program was not realized as landslides in April shut-in six wells. Most of these wells are back on stream. Under the terms of our license, our interest in the field will decrease by half to 10% once the field has produced 60 million barrels, which we expect to occur mid 2009. We expect our share of production to average between 3,000 and 5,000 boe/d in 2009.

Syncrude

Syncrude production decreased 5% to average 21,000 boe/d during the year. Production has been impacted by several factors during the year including: (i) two planned coker turnarounds and other maintenance; (ii) shutdown of the sulphur plant for maintenance; (iii) reduction in shipments of synthetic crude from outages in the Pembina pipeline; and (iv) shortage of bitumen supply as a result of production challenges in the mines, which have since been resolved. In 2009, we expect production to average between 20,000 and 25,000 boe/d.

In late 2008, the Alberta government and the Syncrude owners reached an agreement to amend their existing royalty agreement. The new royalty agreement is expected to increase our after-royalty production volumes.

2007 vs 2006—Higher production increased net income by $1,359 million

Production before royalties increased 20% from 2006 (33% after royalties). This increase reflected the start up of Buzzard production in early 2007, partially offset by declines in our maturing Yemen fields. The addition of high-margin, royalty-free Buzzard volumes increased North Sea production by 64,000 boe/d (net to us). Buzzard production ramped up to peak production in 2007 and produced above design rates during the year. Production in Canada was comparable with 2006 rates as we continued to offset mature base declines with strategic capital investment.

In the Gulf of Mexico, deep-water production from Aspen and Gunnison was down from 2006 from natural field declines. The Wrigley development came on line mid 2007 but rates were lower due to third-party production restrictions. At Syncrude, production was 18% higher than 2006 as the Stage 3 expansion contributed a full year of production.

Commodity Prices

	2008	2007	2006
Crude Oil			
West Texas Intermediate (WTI) (US$/bbl)	99.65	72.31	66.22
Benchmark Differentials[1] (US$/bbl)			
Heavy Oil	20.27	23.44	21.79
Dated Brent	2.66	(0.21)	1.08
Mars	6.21	5.67	7.34
Masila	4.31	0.50	3.00
Realized Prices from Producing Assets (Cdn$/bbl)			
United Kingdom	96.23	76.30	71.19
Yemen	99.87	76.29	71.57
Canada	74.51	44.07	42.79
United States	104.94	69.83	65.80
Other Countries	98.98	71.29	66.09
Syncrude	105.47	79.76	72.32
Corporate Average (Cdn$/bbl)	96.92	73.43	67.50
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	8.90	7.12	6.99
AECO (Cdn$/mcf)	7.71	6.26	6.62
Realized Prices from Producing Assets (Cdn$/mcf)			
United Kingdom	6.78	4.71	7.43
Canada	7.73	6.32	6.49
United States	10.07	7.80	7.86
Corporate Average (Cdn$/mcf)	8.44	6.81	7.18
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	**89.78**	**68.46**	**62.92**
Average Foreign Exchange Rate—Canadian to US Dollar	0.9381	0.9304	0.8818

1 *These differentials are a discount/(premium) to WTI.*

2008 vs 2007—Higher realized prices increased net income $1,614 million

In 2008, commodity prices reached record highs but declined significantly in the fourth quarter. WTI averaged US$99.65/bbl for the year, 38% higher than 2007, while Dated Brent increased 34% over the same period. Our average realized crude oil price increased 32% from $73.43/bbl to $96.92/bbl. During the year, NYMEX gas price increased 25% and AECO increased 23%, averaging US$8.90/mmbtu and $7.71/mcf, respectively. During the same period, our corporate average realized gas price increased 24% to $8.44/mcf, as our gas sales are primarily based off of NYMEX and AECO prices. Compared to 2007, the US dollar weakened relative to the Canadian dollar. As a result, our realized crude oil and natural gas price decreased by approximately $0.80/bbl and $0.07/mcf, respectively and our net sales were lower by approximately $56 million.

Commodity prices fell dramatically during the fourth quarter as the global economic crisis reduced demand for oil and gas. WTI averaged US$58.73/bbl for the quarter, down 50% from the previous quarter and 35% from the same period last year. Our realized average oil price was $59.90/bbl in the fourth quarter compared to $115.56/bbl in the third quarter. NYMEX gas prices also fell during the fourth quarter to average US$6.41/mcf.

Crude Oil Reference Prices

Crude oil prices were volatile in 2008, reaching an all-time high of US$147.27/bbl in mid-July, before declining to close the year at US$44.60/bbl. The increase during the first half of the year was driven by the weakened US dollar and global political tensions as well as by traditional supply and demand fundamentals. The main driver of falling prices in the second half of the year was a weak global economy following the worldwide financial crisis, which dramatically reduced demand for all commodities.

The US dollar weakened during the first half of 2008 and fell to an all-time low against the Euro as the financial markets reacted to the threat of a US recession and the global credit crisis. Investors re-directed their investments into commodity markets to hedge against the weak dollar and inflation, which contributed to the increase in oil prices.

In the second half of the year, the market's focus moved from concerns about adequate future supply to fears of declining demand. Geopolitical events impacting global supply had minimal impact on prices as these events were overshadowed by the weak global economy and declining oil demand. Near-term oil market fundamentals weakened and year-end crude oil inventories were high relative to the last five years.

Crude Oil Differentials

In Canada, heavy crude oil differentials averaged US$20.27/bbl (20% of WTI) for the year, compared to US$23.44/bbl (32% of WTI) in 2007. Demand for heavy oil increased when BP's Whiting refinery came back online in the first quarter of 2008. Declining Venezuelan and Mexican heavy oil production, a slower ramp up of industry oil sands production, higher demand in the summer asphalt season and the desire to run heavier crude in a low refinery margin environment all contributed to narrower differentials earlier in the year. As WTI prices declined in the fall, the heavy differential widened relative to WTI. The onset of winter and seasonally lower demand contributed to the widening differential.

The Brent/WTI differential weakened during 2008, with Brent trading at a discount of US$2.66/bbl compared to a premium of US$0.21/bbl in 2007. The WTI/Brent price differential was volatile in 2008, but WTI traded at a premium to Brent for most of the year. Higher than expected freight costs and storm displacements during the hurricane season increased the WTI premium over Brent, which peaked in November at over US$5.00/bbl. Since then, weak demand and higher Cushing inventories have depressed WTI prices and the differential narrowed late in the year.

The US Gulf Coast Mars differential widened slightly, averaging US$6.21/bbl in 2008 compared to US$5.67/bbl last year. Overall, the differential remained historically high during the year. Higher WTI inventories at Cushing in December caused the WTI/Mars differential to narrow towards the end of the year.

The Yemen Masila differential widened substantially relative to WTI during 2008, averaging US$4.31/bbl compared to US$0.50/ bbl last year. Yemen Masila traded at a discount to WTI in 2008, reflecting the impact of stronger WTI versus Brent pricing as Masila crude is typically priced off Brent.

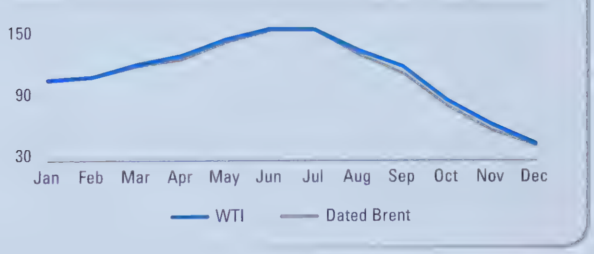
Natural Gas Reference Prices

NYMEX natural gas prices averaged US$8.90/mmbtu in 2008, 25% higher than 2007. Higher crude oil prices, low LNG imports and lower storage levels at the end of the 2007/2008 winter withdrawal season provided support for prices in the first half of the year. Since mid-year, a weak US economy and significant supply increases in unconventional production increased inventory levels and reduced prices. Declining crude oil prices and continuing weakness in the global economy could lead to more LNG cargoes coming to North America during 2009, adding downward pressure on natural gas prices. A colder than expected 2008/2009 winter weather provided some offset to the bearish factors impacting gas prices.

2007 vs 2006—Higher realized prices increased net income $284 million

Average WTI and Dated Brent in US dollars were 9% and 11% higher, respectively, from the prior year, and our average realized crude oil price increased 9% to $73.43/bbl. Our higher average realized price reflects the change in production mix with the addition of new high-quality Buzzard production. This change helped to offset the impact of the weaker US dollar on our Canadian dollar realized prices. Our realized natural gas price fell 5% from 2006 as a result of the stronger Canadian dollar, despite NYMEX increasing 2% in the same period. The weaker US dollar reduced net sales by approximately $225 million, and reduced our realized crude oil and natural gas prices by approximately $3.20/bbl and $0.30/mcf, respectively, as compared to 2006.

2008 MONTHLY AVERAGE OIL PRICE
(US$/bbl)



2008 MONTHLY AVERAGE NATURAL GAS PRICE
(US$/mmbtu)

Operating Expenses

(Cdn$/boe)	2008 Before Royalties[1]	2008 After Royalties	2007 Before Royalties[1]	2007 After Royalties	2006 Before Royalties[1]	2006 After Royalties
Conventional Oil and Gas						
United Kingdom	6.75	6.75	6.94	6.94	11.28	11.28
Yemen	8.51	15.88	6.56	12.00	4.45	8.11
Canada	13.12	16.38	12.91	15.93	10.31	12.73
United States	11.57	13.48	8.43	9.69	8.17	9.45
Other Countries	4.52	4.91	3.45	3.76	2.87	3.13
Average Conventional	8.68	10.40	7.89	9.75	6.95	9.69
Synthetic Crude Oil						
Syncrude	36.53	42.04	25.80	30.32	27.53	30.43
Average Oil and Gas	11.04	13.18	9.45	11.63	8.77	11.96

1 Operating expenses per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2008 vs 2007—Higher operating expenses decreased net income by $121 million

Overall, operating costs increased 14% from 2007, primarily due to Buzzard being on-stream for the full year and higher expenditures at Syncrude. Our production mix continues to change as additional Buzzard volumes are offset by lower volumes in Yemen and the US Gulf of Mexico. Changes in our production profile reduced our corporate average by $0.35/boe, as Buzzard has lower operating costs per barrel.

In the UK North Sea, operating costs increased 19%. The increase is attributable to a full year's production at Buzzard, compared to 2007 when we were ramping up production. In addition, transportation costs increased from higher volumes and increased tariff charges. Elsewhere in the UK North Sea, operating costs increased while production declined, increasing our corporate average by $0.45/boe. The majority of the cost increase is due to platform maintenance at Scott/Telford, including: (i) additional diesel costs for turbine repairs; (ii) maintenance on our water injection and power generation facilities; and (iii) subsea maintenance.

In Yemen, Masila and Block 51 increased our corporate average by $0.32/boe and $0.21/boe, respectively, as a result of lower production rates. Our operating costs are focused on service rig activity and maintenance programs for existing wells. In the US Gulf of Mexico, operating costs were 8% lower than 2007; however, lower production as a result of the hurricanes increased the average unit cost by $0.30/boe.

Operating costs in Canada were marginally higher than last year. Costs in our heavy oil operations increased as a result of higher salaries, utilities and trucking costs. While CBM costs were slightly higher as the number of producing wells increased, the incremental volumes reduced our average cost per barrel. At our natural gas properties, a combination of increased downhole activity and surface maintenance resulted in higher operating costs. These increases were offset by lower costs at our Balzac gas plant, which had a turnaround in the previous year.

Syncrude operating costs were $72 million or 35% higher than the prior year and increased our corporate average by $0.91/ boe. A number of factors contributed to the higher operating costs including: (i) higher contracting costs to increase the mineable ore inventory for bitumen supply; (ii) purchasing additional third-party bitumen to upgrade; (iii) higher natural gas prices in the first half of 2008; and (iv) unscheduled and extended maintenance. We expect Syncrude operating costs will decrease slightly in 2009.

US-dollar denominated operating costs were lower when translated to Canadian dollars as a result of the weaker US dollar for the majority of the year. This decreased our corporate average by $0.23/boe for 2008.

2007 vs 2006—Higher operating expenses decreased net income by $199 million

Our operating costs increased $199 million from 2006 primarily as a result of Buzzard coming on-stream in early 2007 and higher Syncrude production. Our production mix also changed from last year as a result of this production, altering our average unit cost. Operating costs at Buzzard are lower than our corporate average, reducing our corporate average by $1.58/boe. However, the higher-cost Syncrude barrels increased our corporate average by $0.74/boe.

At Masila in Yemen, operating costs increased with higher service rig activity and maintenance programs. The higher costs and lower production increased our corporate average by $0.57/boe. Similarly at Block 51, our operating expenditures were higher as additional service rig activity and higher water handling, fuel and equipment costs increased operating expenditures. The higher costs increased our corporate average $0.37/boe.

Canadian production increased our corporate average $0.50/ boe during the year as a result of industry cost pressures, the extended Balzac turnaround and lower production. Our heavy oil properties have higher unit operating costs as many of the costs are fixed in nature and heavy oil production is declining. Operating costs have also increased with additional CBM wells coming on-stream at Fort Assiniboine. Unit operating costs are initially higher as we de-water the wells to stimulate gas production.

In the Gulf of Mexico, while total operating costs remained consistent year-over-year, lower production increased our corporate average by $0.18/boe. During 2007, industry pressures increased costs and we performed additional downhole and surface maintenance activity to maintain production. However, these costs had minimal impact on our corporate average when compared to last year as our 2006 costs included extended maintenance and turnaround activity at Eugene Island on the shelf.

In the UK North Sea, our Scott/Telford costs increased our corporate average by $0.33/boe. During the year, our total operating expenditures increased as we performed maintenance and work overs on the platform and producing wells, including repairing turbines and improving water injection facilities.

Lower Syncrude operating costs reduced our corporate average by $0.16/boe, and were 6% lower than 2006 as the impact of the higher production from the expansion completed in 2006 was only partially offset by increased maintenance costs. In 2007, maintenance and turnarounds on the Coker 8-3 and the LC Finer interrupted production and increased operating costs.

US-dollar denominated operating costs were lower when translated into Canadian dollars, reducing our corporate average $0.26/boe.

Depreciation, Depletion, Amortization and Impairment (DD&A)

	2008		2007		2006	
(Cdn$/boe)	**Before Royalties[1]**	**After Royalties**	**Before Royalties[1]**	**After Royalties**	**Before Royalties[1]**	**After Royalties**
Conventional Oil and Gas[2]						
United Kingdom	17.72	17.72	19.59	19.59	30.22	30.22
Yemen	7.75	14.45	8.15	14.92	9.67	17.61
Canada	14.99	18.71	12.46	15.37	11.22	13.84
United States	27.46	31.97	22.64	26.03	16.28	18.84
Other Countries	7.90	8.58	3.68	4.06	4.30	4.69
Average Conventional	15.48	18.54	14.94	18.47	13.12	18.30
Synthetic Crude Oil						
Syncrude	6.39	7.35	6.59	7.74	4.81	5.32
Average Oil and Gas	14.71	17.56	14.21	17.49	12.38	16.88

1 DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2 DD&A per boe excludes the impairment charges described in Note 4 of our Consolidated Financial Statements.

2008 vs 2007—Higher oil and gas and Syncrude DD&A decreased net income by $228 million

During the fourth quarter, we recorded non-cash impairment charges of $568 million primarily relating to some properties in the UK North Sea and the Gulf of Mexico. In the North Sea, we recognized an impairment charge of $318 million relating to our Selkirk and Ettrick properties. At Selkirk, we expensed $62 million of allocated acquisition costs as we have no firm development plans. At Ettrick, the impairment charge largely reflects higher costs and lower reserve estimates. In the Gulf of Mexico, our impairment charge relates to four shelf properties ($143 million) and our Green Canyon 6 deep-water property ($107 million). The shelf properties that were impaired are late-life, mature assets that are sensitive to near-term commodity prices. At Green Canyon 6, the impairment expense reflects higher costs after Hurricane Ike destroyed a third-party production platform in the third quarter of 2008. This has resulted in unexpected costs to construct new production facilities and, following an evaluation of options, we expect to have production back on-stream in late 2010.

In the UK, our DD&A expense increased 14% over last year as a result of additional production from Buzzard. The impact of higher production was offset by a lower DD&A rate at Buzzard with the addition of new reserves at the beginning of 2008. The lower depletion rate at Buzzard decreased our corporate average rate by $0.74/boe. Elsewhere in the UK, our depletion rate increased at our mature Scott/Telford and smaller Farragon fields, increasing our corporate average by $0.47/boe.

In the Gulf of Mexico, reserve revisions at the end of 2007 resulted in higher depletion rates in 2008 and increased our corporate average unit cost by $0.59/boe.

Depletion of our Canadian assets increased our corporate average rate by $0.38/boe and is primarily due to our CBM projects in central Alberta. During the year, we invested capital in new wells and facilities. A difference exists between the timing of capital expenditures and the recognition of the reserves. This delay results in high initial depletion rates for our CBM projects. As additional reserves can be recognized, depletion rates should decrease.

In Colombia, our depletion rate doubled from 2007, a result of increased capital costs and lower reserve estimates. This increased our corporate average rate by $0.10/boe.

The stronger Canadian dollar relative to the US dollar decreased our corporate average DD&A rate by $0.45/boe as our US and international depletion is denominated in US dollars.

2007 vs 2006—Higher oil and gas and Syncrude DD&A decreased net income by $636 million

In 2007, our DD&A expense includes $366 million ($3.96/boe) of impairment expense primarily related to our Aspen, Vermilion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our investment in development drilling resulted in negative reserve revisions. While we were encouraged by well log data indicating thick pay zones, well deliverability rates could not be sustained. This likely indicates barriers within this section of the reservoir. At Vermilion 320/340 and West Cameron 170, negative reserve revisions primarily related to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. The carrying values of these properties were reduced to their estimated fair value.

Production from Buzzard increased our corporate average unit DD&A rate by $1.44/boe. Buzzard costs were higher than our corporate average as they include acquisition and project completion costs. We recognized additional proved reserves at the end of 2006 for our other UK assets, which lowered the corporate average $0.59/boe in 2007.

A reduced capital program and slower recovery of capital costs paid on the Yemen government's behalf decreased our corporate average DD&A rate by $0.15/boe.

Depletion of our Canadian assets increased our corporate average by $0.24/boe reflecting the timing of reserve bookings from our CBM projects in central Alberta, and land acquisitions in 2006. In the Gulf of Mexico, unsuccessful development drilling at Aspen and on the shelf increased our capital base, increasing our corporate average rate by $1.29/boe.

Syncrude DD&A includes costs to develop the Stage 3 expansion that came on stream in mid 2006, which increased our corporate average by $0.21/boe.

The strong Canadian dollar relative to the US dollar decreased our corporate average DD&A rate by $0.53/boe as our US and international depletion is denominated in US dollars.

Exploration Expense

(Cdn$ millions)	2008	2007	2006
Seismic	137	123	128
Unsuccessful Drilling	203	126	169
Other	62	77	65
Total Exploration Expense	**402**	**326**	**362**
New Growth Exploration	582	573	491
Geological and Geophysical Costs	137	123	128
Total Exploration Expenditures	**719**	**696**	**619**
Exploration Expense as a % of Exploration Expenditures	56%	47%	58%

2008 vs 2007—Higher exploration expense reduced net income by $76 million

Our total exploration expenditures increased $23 million over last year. We focused our investments on exploratory drilling in the US Gulf of Mexico, UK North Sea and CBM in Canada, and on acquiring seismic data in Norway. Exploration expense increased 23% over the same period due to higher seismic data acquisitions and unsuccessful exploration wells.

In the Gulf of Mexico, we drilled two successful deep-water exploration wells early in 2008 at Green Canyon 448 and Mississippi Canyon 72. Elsewhere in the deep water, we drilled two unsuccessful wells. At Fredericksburg, we drilled to a depth of 24,560 feet but failed to encounter commercial hydrocarbons. This well was subsequently abandoned and $24 million in exploration costs were written off. Our unsuccessful exploration well at Sapphire resulted in a $28 million expense. We are currently drilling our Cote de Mer prospect and results are expected mid 2009.

In the UK North Sea, we had successes at Blackbird, Pink, Bugle and Rochelle. Blackbird is located 6 km south of Ettrick and production could be tied to the Ettrick FPSO, following additional appraisal drilling and development evaluation. At Pink, we drilled a successful exploration well and sidetrack, and we are currently evaluating development options, including co-development with our previous Golden Eagle discovery. We recently completed drilling a successful appraisal well at Rochelle where we have a 44% non-operated interest. Rochelle is located approximately 20 km south of the Scott/Telford fields. During the year, we drilled a dry hole at Full Moon which cost $16 million and we expensed $32 million of drilling costs for our Selkirk prospect which we do not plan to develop at this time.

In Canada, we expensed $67 million for unsuccessful CBM exploration in Alberta. The costs relate to our CBM exploration activities in central Alberta where we have no future development plans. We continue to investigate the CBM potential of other areas.

During 2008, seismic data acquisition costs were 11% higher than 2007. Norway seismic acquisitions increased 47% during the year when we obtained data on newly acquired blocks in the Norwegian North Sea. In the US Gulf of Mexico, our seismic investment decreased from last year as we are focusing on analyzing the seismic data acquired over the past couple of years. Elsewhere, we acquired seismic data in the UK North Sea, Nigeria and Colombia.

2007 vs 2006—Lower exploration expense increased net income by $36 million

We invested almost $700 million in exploration-oriented activities in 2007, primarily related to drilling in the Gulf of Mexico, UK North Sea and CBM in Canada, and acquiring seismic data in the Gulf of Mexico and Norway. In addition, we acquired material land positions in the Gulf of Mexico, and in northeast British Columbia related to an emerging Devonian shale gas play in the Horn River basin.

Exploration expense decreased $43 million or 25% from 2006 as a result of fewer unsuccessful exploration wells. In the Gulf of Mexico, we incurred dry hole costs of $59 million as compared to $135 million in 2006; however, this decrease was partially offset by higher unsuccessful well costs in the UK North Sea, Colombia and Canada.

In the deep-water Gulf of Mexico, we drilled a successful appraisal well at Longhorn and evaluated resource estimates. Development of Longhorn is underway and production is expected to begin in 2009. Also in the deep water, our Vicksburg prospect was drilled to a depth of 25,400 feet and encountered hydrocarbons. Core was recovered from the well and studies are underway to assess the potential productivity. Our unsuccessful drilling results in the Gulf of Mexico were primarily on the shelf where we expensed $35 million for dry holes. In the deep water, we drilled a sidetrack at Aspen targeting two zones in deeper sands; however, results from the lowest zone were unsuccessful and we expensed $20 million for a portion of the drilling costs of the well.

In the UK North Sea, we had several exploration successes. We followed up our successful Golden Eagle well by drilling a sidetrack to appraise the accumulation. Our 2007 dry hole costs in the UK North Sea were $39 million compared to $21 million in 2006. The $15 million Guinea well was completed in the first quarter; however, the target reservoir was water bearing and the well was abandoned. Exploration wells at Stag and Dee were plugged and abandoned, resulting in $12 million and $8 million, respectively, in expensed costs.

In Colombia, we expensed $11 million related to the unsuccessful Guaini-1 and Atalea-1 exploratory wells. In Canada, we expensed costs associated with unsuccessful CBM activities at Provost, Kakwa and Sullivan Lake. Seismic data costs of $123 million were comparable with 2006. The Gulf of Mexico and Norway accounted for 74% of the seismic expenditures, as we consider these areas to have significant exploration potential.

OIL & GAS AND SYNCRUDE NETBACKS

Netbacks are the cash margins, before general and administrative expenses, we receive for every equivalent barrel sold. The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties. A combination of strong realized prices and new high-margin production from Buzzard increased our cash netback by 40% from last year (36% after royalties).

Before Royalties

	2008						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	99.87	58.34	79.02	94.45	98.98	105.47	89.78
Royalties and Other	(46.94)	(12.25)	(11.03)	–	(7.88)	(15.11)	(15.06)
Operating Expenses	(8.51)	(13.12)	(11.57)	(6.75)	(4.52)	(36.53)	(11.04)
In-country Taxes[1]	(13.31)	–	–	–	–	–	(3.04)
Cash Netback	**31.11**	**32.97**	**56.42**	**87.70**	**86.58**	**53.83**	**60.64**

	2007						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	76.29	40.79	58.16	74.79	71.29	79.76	68.46
Royalties and Other	(34.69)	(7.81)	(7.45)	–	(5.90)	(12.02)	(13.10)
Operating Expenses	(6.56)	(12.91)	(8.43)	(6.94)	(3.45)	(25.80)	(9.45)
In-country Taxes[1]	(9.52)	–	–	–	–	–	(2.69)
Cash Netback	**25.52**	**20.07**	**42.28**	**67.85**	**61.94**	**41.94**	**43.22**

	2006						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Royalties and Other	(32.32)	(7.80)	(7.53)	–	(5.51)	(6.93)	(17.68)
Operating Expenses	(4.45)	(10.31)	(8.17)	(11.28)	(2.87)	(27.53)	(8.77)
In-country Taxes[1]	(8.45)	–	–	–	–	–	(3.72)
Cash Netback	**26.35**	**22.87**	**40.42**	**55.53**	**57.71**	**37.86**	**32.75**

After Royalties

	2008						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	99.87	58.34	79.02	94.45	98.98	105.47	89.78
Operating Expenses	(15.88)	(16.38)	(13.48)	(6.75)	(4.91)	(42.04)	(13.18)
In-country Taxes[1]	(24.83)	–	–	–	–	–	(3.63)
Cash Netback	**59.16**	**41.96**	**65.54**	**87.70**	**94.07**	**63.43**	**72.97**

	2007						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	76.29	40.79	58.16	74.79	71.29	79.76	68.46
Operating Expenses	(12.00)	(15.93)	(9.69)	(6.94)	(3.76)	(30.32)	(11.63)
In-country Taxes[1]	(17.42)	–	–	–	–	–	(3.31)
Cash Netback	**46.87**	**24.86**	**48.47**	**67.85**	**67.53**	**49.44**	**53.52**

	2006						
($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Operating Expenses	(8.11)	(12.73)	(9.45)	(11.28)	(3.13)	(30.43)	(11.96)
In-country Taxes[1]	(15.40)	–	–	–	–	–	(5.07)
Cash Netback	**48.06**	**28.25**	**46.67**	**55.53**	**62.96**	**41.89**	**45.89**

1 *Comprises income taxes payable in Yemen that are included in the Government's share of profit oil.*

ENERGY MARKETING

(Cdn$ millions)	2008	2007	2006
Physical Sales [1]	54,772	34,358	30,025
Physical Purchases [1]	(54,047)	(33,417)	(29,060)
Net Financial Transactions [1]	(142)	(61)	344
Change in Fair Market Value of Inventory [1]	(116)	79	–
Marketing Revenue	467	959	1,309
Transportation Expense	(751)	(806)	(789)
Other	27	14	20
Net Marketing Revenue	**(257)**	**167**	**540**
Contribution to Net Marketing Revenue by Region:			
North America	(284)	151	526
Asia	13	11	13
Europe	14	5	1
Net Marketing Revenue	**(257)**	**167**	**540**
Depreciation, Depletion, Amortization and Impairment	(19)	(13)	(12)
General and Administrative	(79)	(87)	(112)
Allowance for Doubtful Receivables	(54)	–	–
Marketing Contribution to Income before Income Taxes	**(409)**	**67**	**416**
North America			
Natural Gas			
Physical Sales Volumes [2] (bcf/d)	6.7	5.8	5.4
Transportation Capacity (bcf/d)	1.8	2.0	3.3
Storage Capacity [3] (bcf)	38	39	50
Financial Volumes (bcf/d)	16.8	21.9	19.8
Crude Oil			
Physical Sales Volumes [2] (mbbls/d)	656	655	553
Storage Capacity (mbbls)	2,578	2,734	1,749
Financial Volumes (mbbls/d)	1,591	2,134	1,976
Power			
Physical Sales Volumes [2] (MW/d)	4,796	4,516	4,388
Generation Capacity (MW/hr)	87	87	87
Asia			
Physical Sales Volumes [2] (mbbls/d)	182	183	152
Financial Volumes (mbbls/d)	349	256	207
Europe			
Financial Volumes (mbbls/d)	787	529	52
Value-at-Risk			
Year End [4]	25	26	26
High	40	38	33
Low	19	24	17
Average	30	30	23

1 *Energy Marketing's physical sales, physical purchases, net financial transactions and changes in fair market value of inventory are reported net on the Consolidated Statement of Income as marketing and other.*

2 *Excludes inter-segment transactions.*

3 *Energy Marketing's storage capacity reflects volumes contracted but not necessarily used.*

4 *Value-at-Risk (VaR) was reduced subsequent to year end. At January 31, 2009, VaR was $20 million.*

2008 vs 2007—Reduced energy marketing net revenue decreased net income by $424 million

The past year proved challenging for our energy marketing group as unprecedented market conditions impacted physical market fundamentals and the pricing relationships we successfully positioned ourselves to profit from historically. In the first half of the year, commodity markets were strong with crude oil prices hitting an all-time high and natural gas pricing near record levels. In the last half of the year, the trend reversed sharply as the US financial crisis intensified and spread globally, curtailing growth and demand for energy commodities.

While the global economic slowdown produced challenges for our business, we were most heavily impacted by the significant volatility in commodity markets as we were not positioned to take advantage of them. Instead, we were positioned to take advantage of normal physical fundamentals but these were overwhelmed by significant downward price movements, increased volatility and the economic slowdown. In mid-2008, we started exiting positions that did not support our physical marketing business and we were scaling back our trading activities in an orderly fashion to minimize losses on closing positions. This was a challenging process given the lack of liquidity in the market, fewer counterparties and deteriorating commodity prices that have eroded natural gas spreads.

The loss in North America was due to losses in our natural gas and NGLs businesses, which were partially offset by contributions from our crude oil and power businesses.

Losses in our natural gas business resulted largely from basis positions designed to take advantage of changing price relationships between locations, as well as financial positions designed to protect the value of our physical transportation capacity contracts. The losses we incurred in mid-2008 related to positions we had taken that were expected to benefit from strengthening natural gas prices in the US Rockies following the addition of new pipeline capacity in the region. Delays in the start-up of this pipeline worked against these positions and resulted in losses as we closed them out mid-year. This left us with trading positions that were expected to benefit from widening east-west location spreads later in the year driven by typical winter demand in eastern consuming gas markets. As we worked to reduce this trading exposure, we were faced with a rapidly deteriorating economic environment in which natural gas prices fell from highs of over US$13.00/mmbtu in the summer to winter prices of approximately US$6.00/ mmbtu in December and US$4.50/mmbtu in January 2009, a period normally characterized by increasing prices. These falling natural gas prices compressed spreads causing losses in the third quarter and additional losses in the fourth quarter as the widening spreads we were positioned for did not materialize and spreads narrowed even further despite cold weather in the east due to demand destruction in the economy. We exited the last of these positions in January 2009.

We also recognized losses on financial positions, including basis, currency and futures contracts, used to hedge our physical transportation capacity contracts. The offsetting gains on our physical capacity contracts cannot be recognized in our results until they are used in the future.

Our marketing results also include losses from our NGL business in the fourth quarter. Over the years, we have been developing this business to take advantage of growing demand for green fuels, such as ethanol, denaturant and propane. The loss reflects declining margins for these products following substantial demand reduction caused by the current economic environment. We are in the process of exiting our ethanol and propane businesses and we expect to complete this by the end of the first quarter.

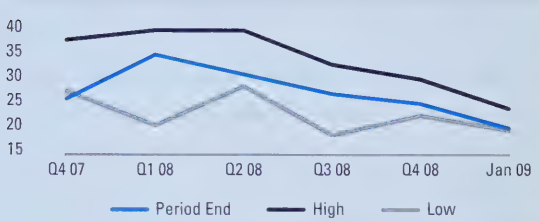
Our crude oil business was positioned to take advantage of daily volatility in both WTI and crude oil quality differentials. Profits were generated primarily by blending activities, by diverting crude oil to more attractive markets and by storing crude oil to capture higher future prices. Losses on financial strategies designed to protect the value of our future storage positions partially offset these gains. A portion of these losses will be recovered in the future when the offsetting gains on the physical positions are recognized.

Our European business has improved their results by focusing on a physical producer/marketer model. We added physical capacity contracts, both storage and transportation, in the UK and continental Europe. Our Asian business continued to generate solid profits by marketing our Masila barrels from Yemen.

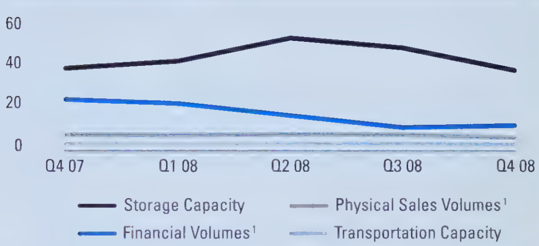
We are realigning our energy marketing strategies and positions to better support our core physical business as a producer/ marketer. We expect to focus on marketing and optimization which involves buying, selling and holding physical commodities, as well as the rights to physical transportation and storage assets. Holding physical assets allows us to extract value when events, particularly weather, cause a disconnect between markets or time periods. Despite recent losses, this business has contributed $380 million of cash flow over the past five years.

We have significantly reduced our financial trading levels in North America and continue to exit positions that do not support our renewed focus. The following graphs show the changes in underlying drivers of our business over the last year and the first month of 2009.

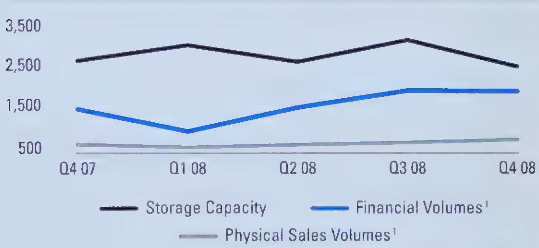
VALUE-AT-RISK



NORTH AMERICAN NATURAL GAS
Volumetric Information (bcf/day)



NORTH AMERICAN CRUDE OIL
Volumetric Information (mbbls/day)



1 *Marketing's physical and financial volumes represent the exiting average daily volume for the quarter.*

The graphs reflect our efforts to re-focus our North American gas business back on its core marketing and optimization activities, as well as prudently manage the working capital deployed in the business.

- Physical volumes are down 25% from their peak with less focus on buying and selling gas at a point to realize a margin.
- At December 31, 2008, financial volumes were down 54% from their peak given our focus on exiting trading positions and optimizing assets.
- Gas storage capacity for the next season is back in line with 2005 levels, giving plenty of capacity to optimize on behalf of ourselves and our customers.

We also reduced the risk held in our forward trading portfolio as demonstrated by reducing our value-at-risk 44% from its peak earlier in the year. Over the past few months, we have significantly reduced our financial trading positions. We have focused our financial contracts on protecting and optimizing the value of our near-term physical assets where market liquidity exists.

The credit crisis that impacted financial markets caused some of our counterparties to restructure or declare bankruptcy. In September 2008, Lehman Brothers filed for bankruptcy protection and our exposure to them in our trading operations was approximately $39 million. The entire amount was expensed in the third quarter although we continue to pursue recovery of these amounts. We also provided an additional $15 million for credit risk with our counterparties. The majority of our counterparties are integrated oil companies, crude oil refiners and marketers, and large utilities.

Results from our marketing group vary between periods and historical results are not necessarily indicative of future results. Marketing results depend on a variety of factors such as market volatility, changes in time and location spreads, the manner in which we use our storage and transportation assets and the change in value of the financial instruments we use to hedge these assets.

2007 vs 2006—Reduced energy marketing net revenue decreased net income by $373 million

Results from our energy marketing group in 2007 were below the record year we experienced in 2006 as there were fewer market events to capitalize on, and fundamental changes in commodity markets were difficult to predict with confidence.

As part of our gas marketing strategy, we hold physical transportation and storage capacity contracts that allow us to take advantage of pricing differences between locations (i.e. west vs. east) and time periods (i.e. summer vs. winter). These strategies, particularly time spreads, contributed less to net revenue in 2007 as there were fewer significant weather-related market events (hurricanes or cold winter weather) to capitalize on. These events typically cause time spreads to widen and location spreads to dislocate, presenting trading opportunities for us. In addition, gas prices were supported throughout the year by high oil prices despite record gas storage levels. We were successful at generating revenue through the day-to-day optimization of our transportation and storage capacity, as well as our fee-for-service asset management activities.

The contribution of our North American crude oil marketing team was lower than 2006 as their portfolio, both physical and financial, was positioned to take advantage of contango (rising forward month prices) in the crude oil forward curve. Late summer, near-term crude oil prices moved up sharply, moving the forward curve from contango to backwardation (falling forward month prices). As a result, we suffered losses in our financial time spread positions. We continued to capture profits from location and quality spreads by diverting crude oil to more attractive markets or blending to enhance crude quality.

Our 2007 results include fair value gains of $79 million on our natural gas and crude oil in storage and pipelines in the fourth quarter. New inventory standards under Canadian GAAP require us to carry our trading commodity inventories at fair value, rather than at cost as was previously the case. We adopted these new rules in the fourth quarter of 2007.

In late 2006, we de-designated certain futures contracts that were designated as cash flow hedges of future sales of our natural gas in storage. These contracts were de-designated since it became uncertain that the future sales would occur within the designated time frame. As it was reasonably possible that the future sales could have taken place as designated at the inception of the hedging relationship, gains of $65 million on the futures contracts were deferred at December 31, 2006. These gains were recognized in marketing and other income during the first quarter of 2007.

Composition of Net Marketing Revenue

(Cdn$ millions)	2008	2007	2006
Trading Activities (Physical and Financial)	(287)	147	520
Non-Trading Activities	30	20	20
Total Net Marketing Revenue	**(257)**	**167**	**540**

Trading Activities

In our energy marketing group, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts using fair value accounting and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is included with accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

Other Activities

We enter into fee for service contracts related to transportation and storage of third-party oil and gas. In addition, we earn income from our power generation facilities at Balzac and Soderglen.

Fair Value of Derivative Contracts

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated, or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

As a basis for establishing fair value, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net short position and the bid price when we have a net long position. This adjustment reflects an estimated exit price and incorporates the impact of liquidity when the bid-ask spread widens in less liquid markets. We incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors, and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those which have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs which are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

At December 31, 2008, the fair value of our derivative contracts in our energy marketing trading activities totaled $63 million. This includes contracts used to economically hedge our physical storage and transportation contracts which cannot be carried at fair value until they are used as well as other trading contracts. Below is a breakdown of the derivative fair value by valuation method and contract maturity.

	Maturity				
(Cdn$ millions)	< 1 year	1–3 years	4–5 years	> 5 years	Total
Level 1 – Actively Quoted Markets	90	(51)	(23)	(3)	13
Level 2 – Based on Other Observable Pricing Inputs	130	(4)	8	(2)	132
Level 3 – Based on Unobservable Pricing Inputs	(80)	(2)	–	–	(82)
Total	**140**	**(57)**	**(15)**	**(5)**	**63**

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	Total
Fair Value at December 31, 2007	6
Change in Fair Value of Contracts	(158)
Net Losses (Gains) on Contracts Closed	227
Changes in Valuation Techniques and Assumptions[1]	(12)
Fair Value at December 31, 2008	**63**

1 *Our valuation methodology has been applied consistently each period, with the exception of two portfolio level reserves that were included in the first quarter of 2008 to account for: a) credit risk associated with counterparty defaults; and b) liquidity risk in our portfolio.*

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. The average term of our derivative contracts is approximately 1.5 years. Those maturing beyond one year primarily relate to North American natural gas positions.

CHEMICALS

(Cdn$ millions)	2008	2007	2006
Net Sales	477	414	407
Sales Volumes (thousand short tons)			
Sodium Chlorate	495	478	487
Chlor-alkali	469	465	451
Operating Profit [1]	125	118	118
Operating Margin [2]	26%	29%	29%
Chemicals Contribution to Income Before Income Taxes [3]	(14)	64	44
Capacity Utilization	92%	94%	95%

1 Net sales less operating costs, transportation and other.
2 Operating profit divided by net sales.
3 Includes foreign exchange gains and losses on long-term debt.

2008 vs 2007—Lower Chemicals contribution decreased net income by $76 million

North America sodium chlorate revenues increased 14% in 2008 as a result of higher realized selling prices and higher sales volumes. Price increases implemented in North America in the first and third quarters more than offset the impact of the stronger Canadian dollar on US-dollar denominated sales. Strong demand from US customers contributed to the increase in sales volumes. North American chlor-alkali revenues were up 11% in 2008 as we realized higher selling prices for caustic soda. These increases have been offset by higher operating and transportation costs, as the price of fuel and power increased during 2008. In Brazil, we have a pass-through contract with our primary customer Aracruz Cellulose that allows us to amend our sales prices when operating costs change. Higher costs in 2008 increased the sales revenues we receive from them.

Chemicals contribution to income includes foreign exchange losses of $54 million, primarily from unrealized losses on the revaluation of US-dollar denominated long-term debt.

2007 vs 2006—Higher Chemicals contribution increased net income by $27 million

Realized North America chlorate prices were up 5% in 2007 and sales volumes remained strong, despite unplanned maintenance of our facilities and pulp mill shut downs. The full effect of the price increase was partially eroded by the strengthening Canadian dollar which reduced US-dollar denominated sales by $9 million. Brazilian sales remained strong with continued demand from our main pulp mill customer Aracruz Cellulose.

Operating profit includes foreign exchange gains of $30 million, primarily from unrealized gains on revaluation of US-dollar denominated long-term debt.

CORPORATE EXPENSES

General and Administrative (G&A)

(Cdn$ millions)	2008	2007	2006
General and Administrative Expense before Stock-Based Compensation	417	336	345
Stock-Based Compensation [1]	(160)	38	210
Total	**257**	**374**	**555**

1 Includes cash and non-cash expenses related to our tandem option plan and stock appreciation rights plan.

2008 vs 2007—Lower costs increased net income by $117 million

Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation expense and related obligations. During the year, we recovered non-cash stock-based compensation costs of $272 million as our stock price closed at $21.45/share at the end of 2008, compared to $32.10/share the previous year. This recovery was partially offset by cash payments for stock-based compensation programs of $112 million, 24% lower than 2007.

G&A expense before stock-based compensation increased $81 million, primarily as a result of higher employee costs and cost inflation. An integral part of our strategy to expand our oil and gas operations has been to actively recruit experienced employees, positioning us for success in our core areas. We have been actively recruiting skilled individuals to strengthen our teams in Norway and the US.

2007 vs 2006—Lower costs increased net income by $181 million

G&A expense dropped 33% from 2006 with lower stock-based compensation expense. At the end of 2007, our stock price closed unchanged from the end of 2006. As a result, most of our 2007 stock-based compensation expense is related to vesting of stock-based compensation plans. Cash payments to employees for stock-based compensation programs increased 24% from 2006 to $147 million.

During the year, we incurred additional employee costs as we continue to expand oil and gas operations internationally and marketing operations in Europe and North America. This was offset by lower variable compensation on oil and gas and marketing operations.

Interest

(Cdn$ millions)	2008	2007	2006
Interest	334	341	294
Less: Capitalized	(240)	(173)	(241)
Net Interest Expense	**94**	**168**	**53**
Effective Interest Rate	5.9%	6.2%	6.3%

2008 vs 2007—Lower net interest expense increased net income by $74 million

Our financing costs are $7 million lower than the previous year as our strong cash flow reduced our debt needs. Lower interest rates on our variable rate debt also reduced interest costs. In the third quarter, we completed an internal reorganization and financing of our assets in the UK. This required us to draw down approximately US$1 billion under our term credit facilities. As a consequence, our financing costs increased in the fourth quarter of 2008.

Interest capitalized on our major development projects increased $67 million in 2008 compared to 2007. Our Long Lake capital costs include $207 million of capitalized interest, $49 million higher than last year. We also capitalized interest of $25 million on our Ettrick development. We continue to capitalize interest on our development project at Usan and the construction of the fourth platform at Buzzard. We expect net interest expense to increase in 2009 by approximately $150 million when we cease capitalizing interest at Long Lake and Ettrick.

2007 vs 2006—Higher net interest expense decreased net income by $115 million

Financing costs increased $47 million from 2006. Additional borrowings to finance our 2007 capital program increased interest costs by approximately $69 million. This was partially offset by the stronger Canadian dollar which reduced our US-dollar denominated interest by $22 million.

Interest capitalized on our major development projects was lower by $68 million from 2006 as we stopped capitalizing interest on the Syncrude Stage 3 expansion and Buzzard when these projects were brought on stream.

Income Taxes

(Cdn$ millions)	2008	2007	2006
Current	859	434	368
Future	598	358	315
Total Provision for Income Taxes	**1,457**	**792**	**683**
Effective Tax Rate	46%	42%	53%

2008 vs 2007—Effective tax rate increases from 42% to 46%

Our provision for income taxes increased $665 million or 84% from the prior year, while our effective tax rate increased 4%. This increase was primarily due to record commodity prices and strong production at Buzzard in the UK, which has a corporate tax rate on oil and gas activities of 50%. Current income taxes include cash taxes in Yemen, the UK, Colombia, Norway and the US.

2007 vs 2006—Effective tax rate decreases from 53% to 42%

Our 2007 effective tax rate was lower than 2006, as we recorded additional tax expense in 2006 due to a UK tax rate increase. Excluding the impact of this rate increase, our effective tax rate in 2006 would have been 33%. The 2007 increase is due to a higher proportion of earnings from the UK where the corporate income tax rate on oil and gas activities is 50%. Current income taxes include cash taxes in Yemen, the UK, Colombia and the US.

Other

(Cdn$ millions)	2008	2007	2006
Increase (Decrease) in Fair Value of Crude Oil Put Options	203	(43)	(11)
Block 51 Settlement	–	–	(151)
Business Interruption Insurance Proceeds	–	–	154

In early 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options establish a Dated Brent floor price of US$60/bbl on these volumes, are settled annually and provide a base level of price protection without limiting our upside to higher prices. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. The put options were purchased for $14 million and are carried at fair value. During the third quarter of 2008, Lehman Brothers, one of the put option counterparties filed for bankruptcy protection, which impacts 25,000 bbls/d of our 2009 put options. The carrying value of these put options has been reduced to nil. At December 31, 2008, the remaining options had a fair value of $233 million, creating an unrealized gain of $203 million.

During 2007, we purchased put options on 36 million barrels of our 2008 crude oil production. These options establish a Dated Brent floor price of US$50/bbl on these volumes. The put options were purchased for $24 million; however, strong crude oil prices reduced the fair value of these options to nil, and we recorded a loss of $24 million during 2007.

During 2006, we purchased put options on approximately 105,000 bbls/d of our 2007 crude oil production for $26 million, establishing a WTI floor price of US$50/bbl on these volumes. We recognized a loss of $7 million for the year ended December 31, 2006 as an increase in the forward WTI prices lowered the fair value of the options. In 2007, strengthening WTI reduced the market value of the options to nil, creating a loss of $19 million.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2006 creating an average floor price for this production of US$38/bbl. Strong WTI prices in 2006 caused us to expense $4 million as the market value of the remaining options was reduced to nil.

In 2006, a court of arbitration concluded that we breached an Area of Mutual Interest agreement with Occidental Petroleum Corporation (Occidental). As a result, Occidental was entitled to monetary damages. In late 2006, we settled the arbitration by agreeing to pay Occidental US$135 million ($151 million) as monetary damages.

In 2006, we received $154 million of business interruption insurance proceeds related to 2005 production losses caused by Gulf of Mexico hurricanes and by generator failures in our UK operations.

OUTLOOK FOR 2009

In 2009, we plan to invest $2.6 billion in capital activities on our oil and gas, and Syncrude operations as follows:

- 34% on our existing producing assets, including the fourth platform at Buzzard;
- 31% in development projects to progress Usan, offshore West Africa and bring Ettrick, in the North Sea, and Longhorn, in the Gulf of Mexico, on stream in 2009;
- 27% on advancing our Horn River shale gas play and on exploration and appraisal opportunities in our key regions—the North Sea, Gulf of Mexico and offshore West Africa; and
- 8% on early stage development projects expected to contribute future production and cash flow including future phases of oil sands in the Athabasca region.

The amount of this capital investment could be reduced due to the current uncertain economic environment. Details of our 2009 capital program are included in the Capital Investment section of the MD&A.

Daily Production

In 2009, we expect net production to grow approximately 10% compared to 2008 and to range between 225,000 and 240,000 boe/d (255,000 and 270,000 before royalties). We expect to ramp up bitumen production at Long Lake as well as first oil production from Ettrick in the North Sea and Longhorn in the Gulf of Mexico. These will more than offset natural field declines in Yemen and a shut-down of the Buzzard platform for four weeks as we install the fourth platform.

2009 Estimated Production

(mboe/d)	2009 Estimated Production Before Royalties	2009 Estimated Production After Royalties	2008 Production Before Royalties	2008 Production After Royalties
United Kingdom	100–115	100–115	103	103
Yemen	40–45	23–28	56	31
Canada	35–40	27–32	38	30
United States	20–25	17–22	22	19
Syncrude	20–25	18–23	21	18
Long Lake Bitumen	20–25	18–23	4	4
Other International	3–5	2–4	6	5
Total	**255–270**	**225–240**	**250**	**210**

Cash Flow and Sensitivities

We expect to generate cash flow of between $2.3 and $2.9 billion from operating activities in 2009, after cash taxes of approximately $1 billion, assuming the following:

WTI (US$/bbl)	$50–$65
NYMEX Natural Gas (US$/mmbtu)	$6.50
US to Canadian Dollar Exchange Rate	$0.83

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities, after cash taxes, as follows:

(Cdn$ millions)	
WTI—US$1/bbl change above US$60	50
WTI—US$1/bbl change below US$60	40
NYMEX Natural Gas—US $0.50/mcf change	34
Exchange Rate—$0.01 US/Cdn change	36

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	December 31 2008	December 31 2007
Net Debt [1]		
Bank Debt	1,448	413
Public Senior Notes	4,582	3,758
Total Senior Debt	6,030	4,171
Subordinated Debt	548	439
Total Debt	6,578	4,610
Less: Cash and Cash Equivalents	(2,003)	(206)
Total Net Debt	**4,575**	**4,404**
Shareholders' Equity	**7,139**	**5,610**

1 Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents

Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows and capital investment. We ended the year with net debt of approximately $4.6 billion, $171 million higher than 2007. The year-over-year change in our net debt results from:

(Cdn$ millions)	2008	2007
Capital Investment	3,066	3,401
Cash Flow from Operating Activities	(4,354)	(2,830)
(Excess) Deficiency	(1,288)	571
Dividends on Common Shares	92	53
Issue of Common Shares	(64)	(56)
Repurchase of Common Shares for Cancellation	338	–
Foreign Exchange Translation of US-dollar Debt and Cash	1,012	(745)
Net Proceeds on Disposition of Assets	(6)	(4)
Other	87	(145)
Increase (Decrease) in Net Debt	**171**	**(326)**

The change in our net debt, combined with strong cash flow and earnings, have improved our 2008 leverage as reflected in the following ratios:

(times)	2008	2007	2006
Net Debt to Cash Flow from Operating Activities	1.1	1.6	2.0
Interest Coverage[1]	15.6	12.1	9.6

1 *Earnings before interest, taxes, DD&A, exploration and other non–cash expenses, divided by interest expense (before capitalized interest).*

Our business strategy is focused on value-based growth through full-cycle exploration and development of conventional and unconventional resources, supplemented by strategic acquisitions when appropriate. Since most of our projects have long cycle-times, requiring significant amounts of capital prior to cash flow generation, we have successfully leveraged our balance sheet many times in the past, including to:

- develop the Masila project in Yemen in 1993;
- acquire Wascana in 1997;
- repurchase 20 million common shares in 2000;
- acquire the remaining interest in Aspen in 2003;
- acquire the Buzzard project and other key assets in the North Sea in 2004; and
- construct the first phase of Long Lake.

Each time, we exceeded our internal net debt to cash flow target band, we successfully bring our leverage down through asset sales and incremental cash flows.

Change in Working Capital

(Cdn$ millions)	December 31 2008	December 31 2007	Increase (Decrease)
Cash and Cash Equivalents	2,003	206	1,797
Restricted Cash	103	203	(100)
Accounts Receivable	3,163	3,502	(339)
Inventories and Supplies	484	659	(175)
Accounts Payable and Accrued Liabilities	(3,326)	(4,180)	(854)
Other	76	22	54
Total	**2,503**	**412**	

Our cash and cash equivalents are significantly higher due to higher operating cash flows and the proceeds of borrowings made on our term credit facilities. Strong production volumes and record commodity prices contributed to higher operating cash flows. We also completed an internal reorganization and financing of our UK assets, which required a draw of approximately US$1 billion under our term credit facilities, with a corresponding increase in cash.

Accounts receivable and payable for our Energy Marketing group decreased $250 million and $600 million from 2007, respectively. These decreases were due to a combination of: (i) lower commodity prices in the fourth quarter of 2008 that reduced the size of our outstanding physical and financial contracts; and (ii) exiting a portion of our derivative positions as part of a strategic decision to reduce the size of our marketing operation. Lower year-end prices also reduced the value of our commodity trading inventories. Additionally, our accrued payables were lower as our outstanding stock-based compensation obligations were reduced by $296 million at the end of 2008.

The stronger US dollar at the end of the year impacted our US-dollar denominated working capital by increasing accounts receivable, inventories and accounts payable by approximately $335 million, $80 million and $290 million, respectively. The US/Canadian year-end exchange rate increased 25% from 2007.

Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow in any given year. We also require liquidity for our energy marketing business. We believe that maintaining strong

liquidity is critical during periods of uncertain economic markets. We currently have liquidity of over $3.5 billion after acquiring the additional Long Lake interest in January 2009 that is comprised of cash and undrawn committed credit facilities available until 2012.

We maintain significant committed credit facilities. At December 31, 2008, we had unsecured term credit facilities of $3.7 billion (US$3.1 billion) that are available until 2012. Of these facilities, $1.2 billion (US$1 billion) was drawn and $381 million (US$311 million) was utilized to support letters of credit. We also had $613 million (US$501 million) of uncommitted, unsecured credit facilities, of which $29 million (US$24 million) was supporting letters of credit outstanding at December 31, 2008. Additionally, Canexus had $420 million (US$343 million) of committed, secured term credit facilities available until 2011 of which $223 million (US$182 million) was drawn down at December 31, 2008.

From time to time, we access capital markets to meet our financing needs. We also use financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI and Dated Brent put options to establish a minimum value for our production. We manage our capital structure to maintain flexibility so we can fund our capital programs given the cyclical nature of the oil and gas business.

The following table shows how we finance our business activities. When our operating cash flows exceed our investment requirements, we generally pay down debt or return cash to shareholders. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn$ millions)	2008	2007	2006	2005	2004
Cash Flow from Operating Activities	4,354	2,830	2,374	2,143	1,606
Cash Flow from Investing Activities	(3,189)	(3,281)	(3,388)	(1,864)	(4,013)
Surplus (Deficiency)	1,165	(451)	(1,014)	279	(2,407)
Cash Flow from Financing Activities	322	677	1,081	(274)	1,426
Net Cash Generated (Used)	**1,487**	**226**	**67**	**5**	**(981)**

In late 2003, we pre-funded debt repayments by raising more than $1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher-cost debt and, coupled with acquisition credit facilities, acquired the North Sea assets. In 2005, we used cash flow and proceeds from asset dispositions to fund our capital program and repay debt. In 2006, we borrowed approximately $1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US$1.5 billion in senior debt to repay outstanding term credit facilities and $150 million in medium term notes, and to fund our 2007 capital program.

In 2008, our cash flow from operating activities exceeded capital expenditures by approximately $1.3 billion and we used this excess to build our cash balances, repurchase common shares and repay debt. In June, we repaid maturing medium term notes of $125 million and in the third quarter, we borrowed approximately US$1 billion under our term credit facilities. The draw down under our term credit facilities resulted from an internal reorganization and financing of our UK North Sea assets.

In the third quarter, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid (Bid). Under the Bid, we are able to repurchase up to 10% of our public float of common shares (approximately 53 million common shares) for cancellation. Purchases under the Bid commenced August 6, 2008 and can be made until August 5, 2009. We repurchased 12 million common shares at an average price of $27.85/share for a cost of $338 million. We currently have no plans to repurchase common shares until economic conditions improve.

Our marketing business also requires liquidity to support its activities. We require liquidity for working capital, cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements typically require collateral be posted if adverse credit-related events, such as reduced credit rating to non-investment grade, occur. Additionally, our exchange-traded contracts require that we provide margin based on daily fluctuations in the value of our contracts. The largest single day margin call we received during 2008 was $60 million. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

Future Liquidity

Our future liquidity depends upon cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Our announced 2009 capital investment budget is approximately $2.8 billion which we expect to finance from cash flow and existing cash. We continue to monitor economic conditions and commodity prices and will adjust our capital investment program accordingly. We are also working with suppliers and contractors to renegotiate supply rates that reflect existing market conditions.

In 2009, we expect cash flow of between $2.3 and $2.9 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US$/bbl)	$50–$65
NYMEX Natural Gas (US$/mmbtu)	$6.50
US to Canadian Dollar Exchange Rate	$0.83

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2009 section on page 65 to see how changes in the above assumptions can impact our cash flow.

At December 31, 2008 we have $2 billion in cash, $2.5 billion (US$2.1 billion) of undrawn committed credit facilities and $613 million of unsecured credit facilities. We have no debt maturities over the next few years and the average term of our public debt is approximately 18 years. When we combine these factors with our strategic capital investment plans, we believe we are well positioned to bring our near completion projects to production and pursue our next generation of growth while preserving our liquidity. At the end of 2008, we agreed to acquire an additional 15% interest in the Long Lake Project and the joint venture lands from OPTI Canada Inc. for $735 million. The acquisition closed late January 2009 and was financed using our existing term credit facilities and cash on hand. We now have a 65% interest in the Long Lake Project and are the sole operator of the resource and upgrader.

For the past several years, we have invested significant capital in a number of major development projects including Buzzard and Long Lake. The large capital investment required in these projects is behind us and we expect these assets to make significant contributions to our future cash flows. In addition, we expect Ettrick and Longhorn to contribute to cash flows when they start production in 2009. The cash flows generated from these projects allow us to repay debt or invest in our next generation of new growth projects such as Usan, offshore West Africa and shale gas in the Horn River basin. In 2009, we expect to invest $515 million to progress our Usan development, and $160 million in the UK North Sea to bring Ettrick on stream and assess development options for Blackbird. While these development projects lack exploration risk, they are subject to other risks including higher than anticipated capital costs or delayed start-up. We maintain significant undrawn committed credit facilities to manage these risks. We also have a US$2.5 billion shelf prospectus filed in the US and Canada for sales of debt securities and common shares.

We are well positioned with our current debt structure and have no significant debt repayments until 2011. Our only debt covenant requires us to maintain a long–term debt to EBITDA ratio of less than 3.5. At December 31, 2008, this ratio was approximately 1.2 times. Based on our current debt levels and operations, we do not expect to exceed 3.5 in the foreseeable future.

(Cdn$ millions)	2009	2010	2011	2012	2013
Term Credit Facilities [1]	–	–	–	1,225	–
Long-Term Notes	–	–	–	–	612
Canexus LP Term Credit Facilities	–	–	223	–	–
Canexus LP Notes	–	–	–	–	61
Total	**–**	**–**	**223**	**1,225**	**673**

1 $3.7 billion (US$3.1 billion) available until 2012.

With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets, and flexibility to reduce future capital expenditure programs, we expect to be able to fund all planned capital, dividends and debt repayments, and meet other obligations that may arise from our oil and gas, Syncrude, chemicals and energy marketing operations.

In 2008, the board declared common share dividends of $0.175. In each of the three years preceding 2008, the board declared common share dividends of $0.10 per share each year.

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

		Payments			
(Cdn$ millions)	**Total**	**< 1 year**	**1–3 years**	**4–5 years**	**> 5 years**
Long-Term Debt	6,652	–	223	1,898	4,531
Interest on Long-Term Debt[1]	7,611	331	662	657	5,961
Operating Leases[2]	715	91	224	205	195
Capital Leases	125	6	12	12	95
Energy Commodity Contract Liabilities	956	636	290	25	5
Transportation and Storage Commitments[2]	1,261	379	411	267	204
Work Commitments and Purchase Obligations[3]	4,228	2,029	1,557	567	75
Asset Retirement Obligations	2,393	35	70	305	1,983
Total	**23,941**	**3,507**	**3,449**	**3,936**	**13,049**

1 *Excludes interest on term credit facilities of $3.7 billion (US$3.1 billion) and Canexus term credit facilities of $420 million (US$343 million) as the amounts drawn on the facilities fluctuate. Based on amounts drawn at December 31, 2008 and existing variable interest rates, we would be required to pay $19 million per year until the outstanding amounts on the term credit facilities are repaid.*

2 *Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.*

3 *Some of these payments relate to work commitments that we can cancel without penalties or additional fees.*

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur.

- Short-term and long-term debt amounts are included on our December 31, 2008 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allow our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to production at Long Lake.
- Energy commodity contract liabilities include the purchase and sale of physical quantities of oil and natural gas, and financial derivatives used to manage our exposure to commodity prices. For contracts where the price is based on an index, the amount is based on forward market prices at December 31, 2008. For certain contracts, we may net settle. These contracts are included in our Consolidated Balance Sheet at fair value.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and include commitments for the Usan development project in Nigeria over the next five years ($1,024 million). Also, included in purchase obligations is $735 million payable in January 2009 for purchasing an additional 15% ownership interest in the Long Lake Project. Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates. The majority of our 2009 capital investment is discretionary.
- We have included $1,409 million in work commitments for drilling rigs we have contracted in the UK, Norway and the Gulf of Mexico, over the next five years.
- We have $2,393 million of undiscounted asset retirement obligations after inflation. As of December 31, 2008, the discounted value ($1,059 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including $35 million of estimated current obligations). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have unfunded obligations of $171 million (Nexen—$112 million; Canexus—$9 million; Syncrude—$50 million) under our defined benefit pension plans. Our obligations for Nexen and Canexus include $63 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit. In addition, existing market conditions created a solvency deficiency of $46 million for the Nexen defined benefit pension plan during the year. While we were required to fund this over the next five years, we funded this shortfall in February 2009.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are not determinable.

- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2009.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when future payments would be required.

From time to time, we enter into contracts that require us to indemnify parties against possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe existing indemnifications would not have a material adverse effect on our liquidity, financial condition or results of operations.

Credit Ratings

Currently, our senior debt is rated Baa2 by Moody's Investor Service, Inc. (Moody's), BBB by Dominion Bond Rating Service (DBRS) and BBB- by Standard & Poor's (S&P). DBRS and S&P currently rate our outlook as stable. Moody's has placed our rating under review for possible downgrade. We believe our strong financial results, ample liquidity and financial flexibility continue to support our credit ratings.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event, such as a drop in credit ratings, occurs. Based on contracts in place and commodity prices at December 31, 2008, we could be required to post collateral of up to $1.3 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts and lowers our available liquidity. Just as we may be required to post collateral if we were downgraded below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us if they are downgraded to non-investment grade.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees on page 69 and in Note 16 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2008, we had outstanding letters of credit supported by $381 million (US$311 million) of unsecured term credit facilities and $29 million (US$24 million) of uncommitted unsecured credit facilities.

Contingencies

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 16 to the Consolidated Financial Statements, which is incorporated here by reference for a discussion of our contingencies.

CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect: i) the reported amounts of our assets and liabilities; ii) the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements; and iii) our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of derivative assets and liabilities, capital adequacy, and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

Oil and Gas Accounting—Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties.

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for the estimates of the quantities of proved oil and gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

Reserve estimates for each property are internally prepared at least annually by the property's reservoir engineer and geoscientists. They are reviewed by engineers familiar with the property and by divisional management. An Executive Reserves Committee, including our CEO, CFO and board-appointed internal qualified reserves evaluator, meet with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator assesses whether our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included as an exhibit to this Form 10-K.

Our reserves are based on internal estimates. To increase our confidence in our estimates, we have at least 80% of our oil and gas and Syncrude reserves either evaluated or audited annually by independent qualified reserves consultants. Given that reserve estimates are based on numerous assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio often differ by significantly more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest.

The nature and extent of the independent evaluations and audits, and the results thereof, are provided in the section on Reserves, Production and Related Information on page 15.

The Board of Directors has a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas and Syncrude reserves and disclosures of reserves data and related oil and gas and mining activities. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with the internal qualified reserves evaluator and independent reserves consultants, independent of management, to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence. In the event of a proposed change to the areas of responsibility of either an independent reserves consultant or the internal qualified reserves evaluator, the Reserves Committee inquires whether there have been disputes between the respective party and management.

The Reserves Committee has reviewed our procedures for preparing the reserves estimates and related disclosures. It reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result, the Reserves Committee is satisfied that the internally-estimated reserves are reliable and

free of material misstatement. Based on the recommendation of the Reserves Committee, the board has approved the reserves estimates and related disclosures in the Form 10-K.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2008, $203 million of our total $401 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by $125 million, net of income tax.
- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2008, oil and gas and Syncrude depletion of $1,340 million (before impairments) was recorded in depletion, depreciation, amortization and impairment expense. If our reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $134 million, assuming no other changes to our reserves profiles.
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

Impairments

Property, Plant and Equipment

We evaluate our long-lived assets (oil and gas properties, Syncrude and chemicals) for impairment if an adverse event or change occurs. Among other things, these might include falling oil and gas prices, a significant negative revision to our reserve estimates, changes in operating and capital costs, or significant or adverse political or regulatory changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flow for a property is less than the carrying amount of that property, we estimate its fair value using a discounted cash flow model.

Cash flow estimates for our impairment assessments require assumptions about the following primary elements—future prices, reserves and discount rates. Our estimates of future prices are based on our assumptions of long-term prices and operating and development costs and require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US$32.20/bbl to US$147.27/bbl and US$4.20/mmbtu to US$15.38/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts, our own assessments and existing future strip prices. Our estimates of discount rates include consideration of the marketplace and risk of the asset. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in these estimates would impact all businesses with the exception of chemicals and energy marketing.

It is difficult to determine and assess how a decrease in proved reserves impacts our impairment tests. The relationship between our reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Goodwill

We test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount and at least annually. Our goodwill impairment test is a two-step process. First, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds the fair value, the second step is required. The second step allocates the fair value of the reporting unit to its underlying assets and liabilities, resulting in an implied fair value of goodwill. If the carrying amount of the reporting unit exceeds the implied fair value of that goodwill, an impairment loss equal to the excess is recorded in net income.

The process of assessing goodwill for impairment necessarily requires us to determine the fair values of our assets using one or more valuation techniques including present value calculations of estimated future cash flows. This process involves

making various assumptions and judgments about future commodity prices, future income, operating costs and discount rates. Changes in any of these assumptions or judgments could result in an impairment of all or a portion of goodwill.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years into the future. Additionally, contracts and regulations are often vague and unclear as to what constitutes removal and remediation. Furthermore, the ultimate financial impact is not always clearly known and cannot be reasonably estimated as asset removal and remediation techniques and costs are constantly changing, as are legal, regulatory, environmental, political, safety and other such considerations.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the future value of the estimated retirement obligations associated with our oil and gas wells and facilities, Syncrude assets and chemical plants. In arriving at amounts recorded, numerous assumptions and judgments are made on ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental, political and safety environments. The asset retirement obligations we record increase the carrying cost of our property, plant and equipment and accretes with the passage of time.

A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our net income.

Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and tax purposes. We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of current income tax is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have adequately provided for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

Derivatives and Fair Value Measurements

We enter into contracts to purchase and sell crude oil and natural gas and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes.

The fair value of derivative contracts is estimated. Wherever possible, this estimate is based on quoted market prices, and if not available, on estimates from third-party brokers. We classify the fair value of our derivatives according to a three-level hierarchy based on the amount of observable inputs used to value the instruments. Inputs may be: 1) readily observable; 2) market corroborated; or 3) generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk. Additionally, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net open sell position and the bid price when we have a net open buy position. We incorporate the credit risk associated with counterparty default into our estimates of fair value.

Our assessment of the significance of a particular input to the fair value measurement may affect the valuation of fair value within the hierarchy. Also for derivative contracts, the time between inception and settlement of the contract may affect fair value. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future operating results.

NEW ACCOUNTING PRONOUNCEMENTS

International Financial Reporting Standards Adoption Plan

In February 2008, the AcSB confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. We are currently assessing the impact of the convergence of Canadian GAAP with IFRS on our results of operations, financial position and disclosures. A project team has been established to manage this transition and to ensure successful implementation within the required time frame.

The project team consists of dedicated personnel who have the experience and IFRS knowledge to ensure success within the required time frame. A steering committee comprised of senior management has been established for project oversight. The

steering committee has the responsibility to ensure the project is adequately planned in sufficient detail, appropriate resources are available, necessary milestones are established and project progress is properly monitored. These senior leaders are also responsible for internal controls over financial reporting and our disclosure controls and procedures.

We recognize that the changeover to IFRS has complex implications on a combination of accounting, IT and business systems, and that there are many aspects to IFRS that we are unfamiliar with. Consequently, we engaged a major accounting firm to provide training and education, and to advise and assist us with identifying accounting treatment differences between IFRS and Canadian GAAP. In addition, based on their previous conversion engagements, we expect our advisor to be able to create efficiencies in our conversion effort by sharing their experiences and informing us of best practices.

Our project consists of five phases: (i) Diagnostic; (ii) Design and Plan; (iii) Develop Solution; (iv) Implementation; and (v) Closeout. We are currently in the Design and Plan phase. During this phase, we are identifying differences between Canadian GAAP and IFRS, gathering information and financial data to assess the potential impacts of these differences, and making recommendations for IFRS accounting policy decisions. Discussion papers are being prepared to properly document the information gathered and support our rationale for our accounting policy recommendations. Factors such as financial and key performance indicator impacts, information technology and systems, internal control environment, treasury, human resources, and general business impacts are outlined in the papers.

Major accounting policy change decisions are expected to be evaluated in early 2009. Our oil and gas business follows successful efforts accounting as described in Note 1 of our Consolidated Financial Statements. Our preliminary review of IFRS indicates that the majority of our existing oil and gas accounting policies are acceptable under IFRS. However, the analysis and comparison between our existing accounting policies and IFRS is complex. Our goal is to choose policies that most accurately reflect the underlying economic results of our operations and financial position within the IFRS framework.

Following completion of the Design and Plan stage, we will be involved with the Develop Solution and Implementation phases throughout the remainder of 2009 and into 2010. We will provide additional disclosures of the key elements of our plan and progress of the project as the information becomes available.

Canadian Pronouncements

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for recognizing assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We do not expect the adoption of this section to have a material impact on our results of operations and financial position.

In January 2009, the AcSB issued Section 1582, *Business Combinations*, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011, with earlier adoption permitted. We plan to adopt this standard prospectively effective January 1, 2009 and do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the AcSB issued Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in Consolidated Financial Statements subsequent to a business combination. These statements are effective on or after the beginning of the first annual reporting period beginning on or after January 2011, with earlier adoption permitted. We plan to adopt these standards prospectively effective January 1, 2009 and do not expect the adoption to have a material impact on our results of operations or financial position.

US Pronouncements

In December 2007, FASB issued Statement 141 (revised), *Business Combinations*. Statement 141 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Non-controlling Interests In Consolidated Financial Statements*, an amendment of ARB No. 51. This statement clarifies that a non-controlling interest in a subsidiary should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In March 2008, FASB issued Statement 161, *Disclosures about Derivative Instruments and Hedging Activities*, an amendment of FASB Statement 133. The statement requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged position. The statement also requires the disclosure of the location and amounts of derivative instruments in the financial statements. This statement is effective for fiscal years and interim periods beginning on or after November 15, 2008. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2008, FASB issued FSP FAS 132 (R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. This position provides guidance on disclosures about plan assets of a defined benefit pension or other postretirement plans, effective for fiscal years ending after December 15, 2009. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2008, the SEC issued Rule 33-8995 *Modernization of Oil and Gas Reporting*. These rules revise oil and gas reporting disclosure requirements and are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. These rules are effective for reports filed after January 1, 2010; earlier adoption is not permitted. We are currently evaluating the impact of these rules on our reserve estimates and disclosures.

ITEM 7A.

Quantitative and Qualitative Disclosures about Market Risk

We are exposed to normal market risks inherent in the oil and gas, Syncrude, energy marketing and chemicals businesses, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

NON-TRADING

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, including the current global financial crisis, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for exploration and development.

Our crude oil prices are based on various reference prices, primarily WTI and Brent and other prices which generally track the movement of WTI and Brent. Adjustments are made to the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

We are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and supply and demand fundamentals, and to a lesser extent local market conditions.

In 2008, WTI averaged US$99.65/bbl, reaching a high of US$147.27/bbl and a low of US$32.40/bbl. Dated Brent, on which approximately 64% of our production is priced, averaged US$96.99/bbl, reaching a high of US$144.22/bbl and a low of US$33.66/bbl. NYMEX natural gas prices averaged US$8.90/mmbtu in 2008, reaching a high of US$13.69/mmbtu and a low of US$5.21/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2009 cash flow from operating activities and net income are as follows:

(Cdn$ millions)	Cash Flow	Net Income
WTI—US$1/bbl change above US$60	50	44
WTI—US$1/bbl change below US$60	40	35
NYMEX Natural Gas—US$0.50/mcf change	34	23

These sensitivities are based on our estimated 2009 oil and gas production and assume a Canadian/US dollar exchange rate of $0.83. Our estimated oil and gas production range for 2009 is between 255,000 and 270,000 boe/d before royalties, of which approximately 16% is gas.

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In 2008, we purchased Dated Brent put options to manage the commodity price risk exposure on a portion of our oil production in 2009. These put options have established an annual average Dated Brent floor price of US$60/bbl on about 45,000 bbls/d of production.

Foreign Currency Risk

A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations; and
- short-term and long-term borrowings.

The Canadian/US dollar exchange rate averaged $0.94 in 2008, ranging from a low of $0.77 to a high of $1.03.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2009 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

(Cdn$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-term Debt
$0.01 Change in US to Cdn	36	18	23	50

Our sensitivities to changes in the Canadian/US dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar denominated long-term debt for 2009. These estimates are based on a WTI price for crude oil ranging between US$50/bbl and US$65/bbl, a NYMEX natural gas price of US$6.50/mmbtu and a Canadian/US dollar exchange rate of $0.83.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations.

Our chemicals operations are exposed to changes in the US-dollar exchange rate as part of their sales are denominated in US dollars. Canexus periodically purchases US-dollar call options to reduce this exposure. As part of the technical conversion project, Canexus also has a contract in Japanese Yen. To manage these exposures, Canexus had the following outstanding option contracts at December 31, 2008:

- the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.82 from January 1, 2009 to December 31, 2009;
- the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.817 from January 1, 2009 to December 31, 2009; and
- a forward exchange contract to purchase 1.74 billion Japanese Yen (JPY) at a rate of 108.11 JPY per US dollar on May 20, 2009.

We do not have any material exposure to highly inflationary foreign currencies.

Interest Rate Risk

We are exposed to fluctuations in interest rates on our floating-rate debt. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2009 cash flow from operating activities and net income is as follows:

(Cdn$ millions)	Cash Flow	Net Income
Interest Rates—1% change in rates	12	9

Our sensitivity to changes in interest rates is based on 2009 estimated average floating-rate debt of $1.2 billion and a Canadian/US dollar exchange rate of $0.83.

Our floating-rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating-rate borrowings and facilities. At December 31, 2008, fixed-rate borrowings comprised 78% (2007—91%) of our long-term debt at an effective average rate of 6.4% (2007—6.3%). During the year, we periodically borrow under our committed, unsecured, term credit facilities and at December 31, 2008, floating-rate debt comprised 22% (2007—9%) of our long-term debt at an effective average rate of 2.7% (2007—5.8%) ranging from a low of 1.0% to a high of 7.8% during 2008.

We had no interest rate swaps outstanding in 2008 or 2007.

TRADING

Commodity Price Risk

Our marketing business is focused on providing services to our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities in selected regions of the globe including crude oil, natural gas, electricity and other commodities. We do this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers.

In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

We also seek to profit from our views on the future direction of energy commodity pricing relationships, primarily between different locations, time periods or qualities. We do this by holding open positions, where the terms of physical or financial contracts are not completely matched to offsetting positions. We may also carry exposures to the absolute change in commodity prices based on our market views or as a consequence of managing our physical and financial positions on a day-to-day basis.

The physical and financial marketing and trading activities we undertake expose us to the risk of loss (and provide the opportunity to profit) from a range of factors including:

- changes to the absolute level of commodity prices;
- changes in the prices of commodities at specific locations;
- changes in the relative level of nearer term prices to future prices;
- changes in the relative value of different qualities of a commodity;
- changes in the volatility of commodity prices;
- changes in the relationships between energy commodity prices and/or derivative instruments;
- changes in the operational costs of our physical transportation and storage contracts;
- physical or financial loss of physical product; and
- disputes over terms of deals and contracts.

In order to manage these risks we have risk management systems and processes including:

- regular reporting to the Board of Directors;
- regular reporting to the Risk Management Committee;
- oversight of activities by experienced commercial management;
- a separate Risk Management Office; and
- comprehensive policies, procedures and controls.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two day holding period in our measure, although actual results can differ from this estimate in non-normal market conditions, or if positions are held longer than two days based on market views or a lack of market liquidity to exit them, which is typical for long-term assets. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available, and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" (for natural gas since May 2006) distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor and report our positions against these VaR limits daily. Our year end, annual high, annual low and average VaR amounts are as follows:

(Cdn$ millions)	**2008**	**2007**	**2006**
Value-at-Risk			
Year End	25	26	26
High	40	38	33
Low	19	24	17
Average	30	30	23

If market shock occurred as in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of non-normal changes in prices on our positions.

Throughout the second half of 2008 and into 2009, we have been realigning our marketing strategies and positions to focus more on physical business which has been built around storage, blending and transportation. To this end, we are reducing our trading levels in an orderly fashion recognizing the challenging economic environment and we have reduced the overall size of our trading business to reduce volatility and focus on the physical side of our business. We are exiting trading positions that do not support our physical business and we are continuing to reduce trading exposures.

CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities and are subject to normal industry credit risk. Approximately 71% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a formal credit process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the board;
- set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. During 2008, we have taken the following specific actions for certain counterparties deemed to be at higher risk of non-performance:

- ceased trading activities;
- significantly reduced and, in some cases, revoked credit privileges;
- redirected business to i) exchanges or clearing houses; and ii) entities with physical-based operations;
- increased "set off" arrangements with counterparties; and
- increased collateral and margining requirements where possible.

At December 31, 2008, only one counterparty individually made up more than 10% of our credit exposure. This counterparty is a major integrated oil company with a strong investment grade rating. No other counterparties made up more than 5% of our credit exposure. In addition, the following table illustrates the composition of credit exposure by credit rating.

Credit Rating	2008	2007
A or Higher	65%	68%
BBB	29%	27%
Non-investment Grade	6%	5%

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as accounts receivable, as well as the fair value of derivative financial assets. In September, Lehman Brothers filed for bankruptcy protection and our exposure at the time was approximately $39 million. This amount was written off, however, we continue to pursue recovery of these amounts. We also provided an additional $15 million for credit risk with our counterparties. We are closely monitoring credit exposures. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value. We based our credit risk estimates, to the extent possible, on market observable inputs such as bond spreads.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations*, constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act* of 1995, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemical prices;
- future production levels;

- future cost recovery oil revenues from our Yemen operations;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset dispositions;
- future sources of funding for our capital program;
- future debt levels;
- availability of committed credit facilities;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of current and long-term assets;
- ultimate recoverability of reserves or resources;
- expected finding and development costs;
- expected operating costs;
- future demand for chemical products;
- estimates on a per share basis;
- sales;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed or will come on stream; and
- changes in any of the foregoing.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

- market prices for oil and gas and chemical products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- volatility in energy trading markets;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings; and
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the section, titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures about Market Risk* in Item 7A. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, we undertake no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a voluntary Form 10-K (and related forms) filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In Canada, *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) prescribes that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. Nexen reserves disclosures are made in reliance upon exemptions granted to Nexen by Canadian securities regulators from certain requirements of NI 51-101 which permits us to:

- prepare our reserves estimates and related disclosures in accordance with SEC disclosure requirements, generally accepted industry practices in the US and the standards of the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) modified to reflect SEC requirements;
- substitute those SEC disclosures for much of the annual disclosure required by NI 51-101; and

- rely upon internally-generated reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, without the requirement to have those estimates evaluated or audited by independent qualified reserves evaluators.

As a result of these exemptions, Nexen's disclosures may differ from other Canadian companies and Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their proved reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using year-end constant prices and costs only whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved developed reserves by geographic region only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not prescribe the nature of the information required in connection with proved undeveloped reserves and future development costs whereas NI 51-101 requires certain detailed information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions whereas NI 51-101 requires that various F&D costs per boe be disclosed. NI 51-101 requires that F&D costs be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year;
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's Board of Directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports;
- the SEC does not consider the upgrading component of our integrated oil sands project at Long Lake as an oil and gas activity, and therefore permits recognition of bitumen reserves only. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits recognition of synthetic reserves. At year end, we have recognized 285 million barrels before royalties of proved bitumen reserves (282 million barrels after royalties) under SEC requirements, whereas under NI 51-101 we would have recognized 233 million barrels before royalties of proved synthetic reserves (231 million barrels after royalties);
- the SEC considers our Syncrude operation as a mining activity rather than an oil and gas activity, and therefore does not permit related reserves to be included with oil and gas reserves. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits them to be included with oil and gas reserves. We have provided a separate table showing our share of the Syncrude proved reserves as well as the additional disclosures relating to mining activities required by SEC requirements; and
- any reserves data in this document reflects our estimates of reserves. While we obtain an independent assessment of a portion of our reserves estimates, no independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data disclosed in this Form 10-K.

The foregoing is a general description of the principal differences only.

Please note that the differences between SEC requirements and NI 51-101 may be material.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead; and
- because reserves data are based on judgments regarding future events actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.

FINANCIAL STATEMENTS

A strong balance sheet
allows us to fund our capital programs
and pursue strategic opportunities.

PART II

ITEM 8.

ITEM 9.

ITEM 9A.

Controls and Procedures

ITEM 8.

REPORT OF MANAGEMENT

February 11, 2009

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and fair presentation of the Consolidated Financial Statements, as well as the financial reporting process that gives rise to such Consolidated Financial Statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our Consolidated Financial Statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for the development and implementation of internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company, and that our records are reliable for preparing our Consolidated Financial Statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer or Controller.

Our Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee), with assistance from the Reserves Review Committee regarding the annual review of our petroleum, natural gas and Syncrude reserves, and the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors and includes three directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws), pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "Marvin F. Romanow"
President and Chief Executive Officer

(signed) "Kevin J. Reinhart"
Senior Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the accompanying Consolidated Balance Sheets of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related Consolidated Statements of Income, Cash Flows, Shareholders' Equity and Comprehensive Income for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of Nexen Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 11, 2009

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 1(u) to the Consolidated Financial Statements. Our report to the Board of Directors and shareholders on the Consolidated Financial Statements of the Company dated February 11, 2009, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 11, 2009

NEXEN INC.
CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions, except per share amounts	**2008**	**2007**	**2006**
Revenues and Other Income			
Net Sales	7,424	5,583	3,936
Marketing and Other (Note 17)	813	1,021	1,450
	8,237	6,604	5,386
Expenses			
Operating	1,335	1,165	955
Depreciation, Depletion, Amortization and Impairment (Note 4)	2,014	1,767	1,124
Transportation and Other	967	908	1,041
General and Administrative	257	374	555
Exploration	402	326	362
Interest (Note 10)	94	168	53
	5,069	4,708	4,090
Income before Provision for Income Taxes	3,168	1,896	1,296
Provision for Income Taxes (Note 18)			
Current	859	434	368
Future	598	358	315
	1,457	792	683
Net Income before Non-Controlling Interests	1,711	1,104	613
Net Income (Loss) Attributable to Non-Controlling Interests	(4)	18	12
Net Income	**1,715**	**1,086**	**601**
Earnings Per Common Share ($/share) (Note 19)			
Basic	3.26	2.06	1.15
Diluted	3.22	2.02	1.12

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2008 AND 2007

Cdn$ millions, except share amounts	2008	2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	2,003	206
Restricted Cash	103	203
Accounts Receivable (Note 2)	3,163	3,502
Inventories and Supplies (Note 3)	484	659
Other	169	89
Total Current Assets	5,922	4,659
Property, Plant and Equipment (Note 4)	14,922	12,498
Goodwill	390	326
Future Income Tax Assets (Note 18)	351	268
Deferred Charges and Other Assets (Note 6)	570	324
TOTAL ASSETS	**22,155**	**18,075**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable and Accrued Liabilities (Note 9)	3,326	4,180
Accrued Interest Payable	67	54
Dividends Payable	26	13
Total Current Liabilities	3,419	4,247
Long-Term Debt (Note 10)	6,578	4,610
Future Income Tax Liabilities (Note 18)	2,619	2,290
Asset Retirement Obligations (Note 12)	1,024	792
Deferred Credits and Other Liabilities (Note 13)	1,324	459
Non-Controlling Interests	52	67
Shareholders' Equity (Note 15)		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2008—519,448,590 shares		
2007—528,304,813 shares	981	917
Contributed Surplus	2	3
Retained Earnings	6,290	4,983
Accumulated Other Comprehensive Loss	(134)	(293)
Total Shareholders' Equity	7,139	5,610
Commitments, Contingencies and Guarantees (Notes 16 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**22,155**	**18,075**

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Marvin F. Romanow"
Director

(signed) "Thomas C. O'Neill"
Director

NEXEN INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions	**2008**	**2007**	**2006**
Operating Activities			
Net Income	1,715	1,086	601
Charges and Credits to Income not Involving Cash (Note 20a)	2,136	2,073	1,629
Exploration Expense	402	326	362
Changes in Non-Cash Working Capital (Note 20b)	119	(348)	(177)
Other	(18)	(307)	(41)
	4,354	2,830	2,374
Financing Activities			
Proceeds from Long-Term Notes	–	1,660	–
Repayment of Medium-Term Notes and Debentures	(125)	(150)	(93)
Proceeds from (Repayment of) Term Credit Facilities, Net	803	(697)	1,044
Proceeds from (Repayment of) Short-Term Borrowings, Net	(4)	(150)	160
Proceeds from Canexus Notes	51	–	–
Proceeds from (Repayment of) Term Credit Facilities of Canexus, Net	(20)	60	2
Dividends on Common Shares	(92)	(53)	(52)
Distributions Paid to Non-Controlling Interests	(17)	(28)	(28)
Issue of Common Shares and Exercise of Tandem Options for Shares (Note 15b)	64	56	48
Repurchase of Common Shares for Cancellation (Note 15b)	(338)	–	–
Other	–	(21)	–
	322	677	1,081
Investing Activities			
Capital Expenditures			
Exploration and Development	(2,895)	(3,132)	(3,198)
Proved Property Acquisitions	(22)	(151)	(13)
Chemicals, Corporate and Other	(149)	(118)	(119)
Business Acquisitions, Net of Cash Acquired (Note 5)	–	–	(78)
Proceeds on Disposition of Assets	6	4	27
Changes in Non-Cash Working Capital (Note 20b)	(124)	130	134
Changes in Restricted Cash	106	(16)	(127)
Other	(111)	2	(14)
	(3,189)	(3,281)	(3,388)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	310	(121)	(14)
Increase in Cash and Cash Equivalents	1,797	105	53
Cash and Cash Equivalents, Beginning of Year	206	101	48
Cash and Cash Equivalents, End of Year	**2,003**	**206**	**101**

Cash and cash equivalents at December 31, 2008 consists of cash of $355 million and short–term investments of $1,648 million.

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions	2008	2007	2006
Common Shares, Beginning of Year	917	821	732
Issue of Common Shares	41	32	32
Exercise of Tandem Options for Shares	23	24	16
Accrued Liability Relating to Tandem Options Exercised for Common Shares	22	40	41
Repurchased Under Normal Course Issuer Bid (Note 15b)	(22)	–	–
End of Year	**981**	**917**	**821**
Contributed Surplus, Beginning of Year	3	4	2
Stock-Based Compensation Expense	–	1	2
Exercise of Tandem Options	(1)	(2)	–
End of Year	**2**	**3**	**4**
Retained Earnings, Beginning of Year	4,983	3,972	3,423
Net Income	1,715	1,086	601
Dividends on Common Shares	(92)	(53)	(52)
Transition Adjustment on Adoption of New Inventory Standard	–	(22)	–
Repurchase of Common Shares for Cancellation (Note 15b)	(316)	–	–
End of Year	**6,290**	**4,983**	**3,972**
Accumulated Other Comprehensive Loss, Beginning of Year	(293)	(161)	(161)
Opening Derivatives Designated as Cash Flow Hedges	–	61	–
Other Comprehensive Income (Loss)	159	(193)	–
End of Year [1]	**(134)**	**(293)**	**(161)**

1 Includes unrealized foreign currency translation adjustment.

NEXEN INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2008

Cdn$ millions	2008	2007	2006
Net Income	1,715	1,086	601
Other Comprehensive Income (Loss), net of income taxes:			
Foreign Currency Translation Adjustment:			
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	1,228	(867)	16
Net Gains (Losses) on Debt Hedges of Self-Sustaining Foreign Operations [1]	(1,062)	738	(20)
Realized Translation Adjustments Recognized in Net Income	(7)	(3)	4
Cash Flow Hedges:			
Realized Mark-to-Market Gains Recognized in Net Income	–	(61)	–
Other Comprehensive Income (Loss)	159	(193)	–
Comprehensive Income	**1,874**	**893**	**601**

1 Net of income tax recovery for the year ended December 31, 2008 of $145 million (2007—$97 million expense; 2006—$12 million recovery).

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cdn$ millions, except as noted

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 23.

(a) Consolidation

The Consolidated Financial Statements include the accounts of Nexen and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus Limited Partnership and its subsidiaries (Canexus), are wholly owned. All intercompany accounts and transactions are eliminated upon consolidation.

We have a 63.5% interest in Canexus represented by 56.6 million Exchangeable LP Units. We have the right to nominate a majority of the members of the Board of Directors, who have the power to determine the strategic operating, investing and financing policies of Canexus. Through our majority ownership interest and the ability to elect the majority of the members of the board, Nexen holds effective control over Canexus. All assets, liabilities and results of operations of Canexus are consolidated and have been included in our Consolidated Financial Statements. Non-Nexen ownership interests in Canexus are shown as non-controlling interests.

We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. We also proportionately consolidate our 7.23% undivided interest in the Syncrude joint venture, which is considered a mining activity under current US regulations. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(b) Use of estimates

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of derivative assets and liabilities, capital adequacy, and the determination of proved reserves. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(c) Cash and cash equivalents

Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase. These investments are recorded at cost, which approximates fair value.

(d) Restricted cash

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts.

(e) Accounts receivable

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(o)). Our allowance for doubtful accounts provides for specific doubtful receivables, as well as general counterparty credit risk evaluated using observable market information and internal assessments.

(f) Inventories and supplies

Inventories and supplies, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined using the first-in, first-out method. Inventory costs include expenditures and other costs, including depletion, directly or indirectly incurred in bringing the inventory to its existing condition.

Effective October 1, 2007, commodity inventories in our energy marketing operations that are held for trading purposes are carried at fair value, as measured by the one-month forward price, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other income during the period of change.

(g) Property, plant and equipment (PP&E)

PP&E is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the

useful lives of the related assets are capitalized to PP&E. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included with PP&E.

We follow successful efforts accounting for our oil and gas operations. Costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the costs are reclassified to proved property costs. Exploration drilling costs are capitalized as suspended exploration well costs pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized if a determination is made that a sufficient quantity of reserves have been found and sufficient progress is being made to assess the reserves and the economic and operating viability. All other exploration costs, including geological and geophysical and annual lease rentals, are expensed to earnings as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established, and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

(h) Depreciation, depletion, amortization and impairment (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs are depleted over remaining proved reserves. Depletion is considered a cost of inventory when the oil and gas is produced. When the inventory is sold, the depletion is charged to DD&A expense.

Our Syncrude PP&E is depleted using the unit-of-production method. Capitalized costs are depleted over proved and probable reserves within developed areas of interest.

We depreciate other plant and equipment costs using the straight-line method based on the estimated useful lives of the assets, which range from 3 to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur that indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. These events or conditions occur periodically. If carrying value exceeds the sum of estimated undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated total future net cash flows, discounted for the time value of money, and we expense the excess carrying value to DD&A. Our cash flow estimates require assumptions about future commodity prices, ultimate recoverability of oil and gas reserves, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(i) Capitalized interest

We capitalize interest on major development projects until the project is complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(j) Carried interest

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(k) Goodwill

Our goodwill is attributable to our energy marketing and UK operating segments. It has been recorded at cost and is not amortized. We test goodwill for impairment at least annually or whenever events or circumstances indicate that goodwill is impaired. We base our test on estimated future net cash flows of the reporting unit. If goodwill is impaired we reduce the carrying value to estimated fair value and an impairment loss is recorded in net income. No significant impairments arose from the December 2008 and the December 2007 annual tests.

(l) Financial instruments and hedging activities

All financial assets and liabilities are recognized on the balance sheet when we become a party to the contractual provisions of the instrument and are initially recognized at fair value. Subsequent measurement of the financial instruments is based on their classification. We have classified each financial instrument into one of the following categories: financial assets and financial liabilities held for trading; loans or receivables; financial assets held to maturity; financial assets available for sale; and other financial liabilities. The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in very limited circumstances, the classification of financial instruments is not subsequently changed.

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Realized and unrealized gains and losses from financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred.

Financial instruments we carry at cost or amortized cost include our accounts receivable, accounts payable and accrued liabilities, accrued interest payable, dividends payable, short-term borrowings and long-term debt. Transaction costs are included in net income when incurred for these types of financial instruments except for short-term borrowings and long-term debt. These transaction costs are included with the initial fair value and the instrument is carried at amortized cost using the effective interest rate method. Gains and losses on financial assets and liabilities carried at cost or amortized cost are recognized in net income when these assets or liabilities settle.

Derivatives related to non-trading activities

We use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Notes 7 and 8). We record these instruments at fair value at the balance sheet date and record any change in fair value as a net gain or loss in marketing and other income during the period of change unless the requirements for hedge accounting are met.

Derivatives related to trading activities

Our energy marketing operation uses derivative instruments for marketing and trading natural gas, crude oil, natural gas liquids and power including: commodity contracts settled with physical delivery; exchange-traded futures and options; and non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change. The fair value of these instruments is included with accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond twelve months, we include them with deferred charges and other assets or deferred credits and other liabilities.

Hedge accounting

Hedge accounting may be used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income with any ineffectiveness recognized in marketing and other income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Nexen had no cash flow or fair value hedges in place at December 31, 2008 or 2007.

Comprehensive income

Comprehensive income consists of net income and other comprehensive income (OCI). OCI includes gains and losses resulting from the foreign exchange translation of our net investments in self-sustaining foreign operations and the effective portion of derivatives used as a hedging item in a cash flow hedge or net investment hedge. Accumulated other comprehensive income (AOCI) is a separate component of shareholders' equity comprised of the cumulative amounts of OCI. Amounts included in AOCI are reclassified to income when realized.

(m) Asset retirement obligations

We provide for future asset retirement obligations on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The obligation is accreted through DD&A expense until it is expected to settle and the cost is amortized through DD&A expense over the life of the respective asset. The fair value of the obligation is estimated by discounting expected future cash flows estimated to settle the asset retirement obligation using a weighted-average, credit-adjusted risk free interest rate. Nexen recognizes period-to-period changes due to the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile, and our interest in the Long Lake upgrader. The estimated future recoverable reserves at Syncrude and Long Lake are significant and given the long life of these assets, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant and the Long Lake upgrader can both continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the obligation to remediate becomes determinable.

(n) Pension and other post-retirement benefits

Our employee post-retirement benefit programs consist of contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs.

For our defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1% to a maximum increase of 5%.

During the year, we changed our measurement date for defined benefit plans from October 31 to December 31. This change was applied prospectively and did not have a material impact on our financial statements.

Our defined contribution pension plan benefits are based on plan contributions. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependants. Costs are accrued as compensation in the period employees work; however, these future obligations are not funded.

(o) Revenue recognition

Oil and gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the crude oil or natural gas reaches the end of the pipeline. For our other international operations, including the UK, our customers take title when crude oil is loaded onto tankers. When we produce

or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty obligations to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty obligations. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(j).

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery takes place when we have a sales contract specifying delivery volumes and sales prices. We assess customer credit worthiness before entering into sales contracts to minimize collection risk.

Energy marketing

Substantially all of the physical purchase and sales contracts entered into by our energy marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our energy marketing operation are stated at fair value on the balance sheet (see Note 1(l)). We record any change in fair value as a gain or loss in marketing and other income unless requirements for hedge accounting are met.

Any margin earned by our energy marketing operation on the sale of our proprietary oil and gas production is included in marketing and other. Sales of our proprietary production are recorded at monthly average market-based prices and reported in our oil and gas segments. Intercompany profits and losses between segments are eliminated.

We assess customer credit worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have a legally enforceable right and intention to offset.

(p) Foreign currency translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars at the balance sheet date exchange rate for assets and liabilities and at the monthly average exchange rate for revenues and expenses. Gains and losses resulting from this translation are included in other comprehensive income.

We have designated our US-dollar debt (excluding debt related to Canexus) as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other income in the Consolidated Statement of Income.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation are included in marketing and other income in the Consolidated Statement of Income.

(q) Transportation

We pay to transport the crude oil, natural gas and chemical products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as transportation and other expense. Amounts billed to our customers are presented within marketing and other income. Our energy marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments have been recorded as deferred liabilities and are recognized in net income as the transportation is used.

(r) Leases

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases and the related assets are included with PP&E and are amortized on a straight-line basis over the period of expected use, consistent with other PP&E. Rental payments under operating leases are expensed as incurred.

(s) Stock-based compensation

Our stock-based compensation consists of tandem option (TOPs) and stock appreciation right (StARs) plans.

Tandem options to purchase common shares are granted to directors, officers and employees at the discretion of the Board of Directors. Each tandem option gives the holder a right to either purchase one Nexen common share at the exercise price or to receive a cash payment equal to the excess of the market value of the common share over the exercise price. Options granted prior to February 2001 vest over four years and are exercisable on a cumulative basis over 10 years. Options granted

after February 2001 vest over three years and are exercisable on a cumulative basis over five years. At the time of the grant, the exercise price equals the market value.

We record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense in the Consolidated Statement of Income. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

Under our StARs plan, employees are entitled to cash payments equal to the excess of market price of the common share over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan. The total StARs granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares. At the time of grant, the exercise price equals market value. We account for stock appreciation rights to employees on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

(t) Income taxes

We follow the liability method of accounting for income taxes. This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(u) Changes in accounting principles

Capital disclosures

On January 1, 2008, we prospectively adopted Canadian Institute of Chartered Accountants (CICA) Section 1535 *Capital Disclosures* issued by the Canadian Accounting Standards Board (AcSB). This Section establishes standards for disclosing information about an entity's objectives, policies and processes for managing its capital structure. The disclosures have been included in Note 11.

Financial instruments disclosures and presentation

On January 1, 2008, we prospectively adopted the following new standards issued by the AcSB: *Financial Instruments—Disclosure* (Section 3862) and *Financial Instruments—Presentation* (Section 3863). These accounting standards replaced *Financial Instruments—Disclosure and Presentation* (Section 3861). The disclosures required by Section 3862 and 3863 provide additional information on the risks associated with our financial instruments and how we manage those risks. The additional disclosures required by these standards are provided in Notes 7 and 8.

New accounting pronouncements

In February 2008, the AcSB confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. We are currently assessing the impact of the convergence of Canadian GAAP with IFRS on our results of operations, financial position and disclosures. A project team has been set up to manage this transition and to ensure successful implementation within the required timeframe.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for recognizing assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We do not expect the adoption of this section to have a material impact on our results of operations or financial position.

In January 2009, the AcSB issued Section 1582, *Business Combinations*, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning

on or after January 2011 with earlier application permitted. We plan to adopt this standard prospectively effective January 1, 2009 and do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the AcSB issued Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replaces existing guidance. Section 1601 establishes standards for the preparation of Consolidated Financial Statements. Section1602 provides guidance on accounting for a non-controlling interest in a subsidiary in Consolidated Financial Statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. We plan to adopt these standards effective January 1, 2009 and do not expect the adoption will have a material impact on our results of operations or financial position.

2. ACCOUNTS RECEIVABLE

	2008	2007
Trade		
Energy Marketing	2,256	2,501
Oil and Gas	639	819
Chemicals and Other	68	60
	2,963	3,380
Non-Trade	270	132
	3,233	3,512
Allowance for Doubtful Receivables	(70)	(10)
Total	**3,163**	**3,502**

3. INVENTORIES AND SUPPLIES

	2008	2007
Finished Products		
Energy Marketing	384	577
Oil and Gas	17	14
Chemicals and Other	16	13
	417	604
Work in Process	6	3
Field Supplies	61	52
Total	**484**	**659**

4. PROPERTY, PLANT AND EQUIPMENT

	2008			2007		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	899	781	118	701	590	111
Yemen—Carried Interest	1,909	1,829	80	1,477	1,360	117
Canada [1]	8,134	1,786	6,348	6,736	1,597	5,139
US	4,398	2,702	1,696	3,069	1,765	1,304
UK	6,532	2,159	4,373	4,723	908	3,815
Other Countries	554	113	441	263	77	186
	22,426	9,370	13,056	16,969	6,297	10,672
Energy Marketing	246	76	170	246	62	184
Syncrude	1,372	236	1,136	1,332	205	1,127
Chemicals	940	507	433	831	463	368
Corporate and Other	331	204	127	315	168	147
Total	**25,315**	**10,393**	**14,922**	**19,693**	**7,195**	**12,498**

1 *Includes capitalized costs related to our insitu oil sands (Long Lake and future phases) of $4,742 million (2007—$3,695 million).*

The above table includes capitalized costs of $7,386 million (2007—$5,828 million) relating to unproved properties and projects under construction or development. These costs are currently not being depreciated, depleted or amortized, however we expect to begin amortizing the capitalized costs of Long Lake Phase 1 in early 2009. Our insitu oil sands capitalized costs in Canada include $1,874 million related to the Phase 1 upgrader (2007—$1,711 million); $1,325 million for Phase 1 SAGD and cogeneration facilities (2007—$1,026 million); and $1,543 million related to capitalized interest and future phases (2007—$958 million).

Depreciation, depletion, amortization and impairment

In 2008, our DD&A expense includes $568 million of impairment expense relating to oil and gas properties in the Gulf of Mexico and North Sea. These properties were written down to their estimated fair value based on their estimated total future discounted net cash flows.

In the Gulf of Mexico, we reduced the carrying value of four shelf properties by $143 million, primarily as a result of low oil and gas prices and higher estimated asset remediation costs. These late-life, mature properties have a shorter production horizon, and therefore are sensitive to near-term commodity prices and to higher abandonment costs. Inflationary pressures in the oil and gas industry increased the estimated future costs to remediate the assets. At Green Canyon 6, we reduced the carrying value of our assets by $107 million to reflect the impact of Hurricane Ike which destroyed a third-party production platform in the third quarter of 2008. This resulted in unexpected and uninsured costs to rebuild facilities.

In the North Sea, we reduced the carrying value of our Ettrick project by $256 million, primarily due to higher costs and lower reserve estimates following drilling and testing activities. We also expensed costs of $62 million related to our Selkirk discovery as we currently have no firm plans to continue with development.

In 2007, our DD&A expense includes $366 million of impairment expense primarily related to our Aspen, Vermilion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our investment in development drilling resulted in negative reserve revisions. At Vermilion 320/340 and West Cameron 170, negative reserve revisions primarily related to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. These properties were written down to their estimated fair value equal to estimated total future discounted net cash flows.

Research and development

In 2008, we incurred $30 million (2007—$40 million) in connection with research and development activities related to developing new technologies for increasing oil recoveries. Research costs of $27 million (2007—$38 million) were included in other expense on the Consolidated Statement of Income. The development costs have been deferred and are included in PP&E.

	2008	2007
Beginning of Year	30	28
Deferred in the Year	3	2
Amortized in the Year	–	–
End of Year	**33**	**30**

Suspended exploration well costs

The following table shows the changes in capitalized exploratory well costs during the years ended December 31, 2008 and 2007, and does not include amounts that were initially capitalized and subsequently expensed in the same period.

	2008	2007
Beginning of Year	326	226
Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves	254	215
Capitalized Exploratory Well Costs Charged to Expense	(81)	(10)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(29)	(74)
Effects of Foreign Exchange Rate Changes	48	(31)
End of Year	**518**	**326**

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	2008	2007
Capitalized for a Period of One Year or Less	239	202
Capitalized for a Period of Greater than One Year	279	124
Total	**518**	**326**
Number of Projects with Exploratory Well Costs Capitalized for a Period Greater than One Year	7	5

As at December 31, 2008, we have exploratory costs that have been capitalized for more than one year relating to our interests in two exploratory blocks in the Gulf of Mexico ($120 million), our coalbed methane exploratory activities in Canada ($70 million), three exploratory blocks in the North Sea ($67 million), and our interest in an exploratory block offshore Nigeria ($22 million). These costs relate to projects with exploration wells for which we have not been able to record proved reserves. We are assessing all of these wells and projects, and are working with our partners to prepare development plans, drill additional appraisal wells or to assess commercial viability.

5. BUSINESS ACQUISITIONS

In 2006, we completed business acquisitions related to our energy marketing group for $78 million, net of cash acquired. These acquisitions were accounted for using the purchase method of accounting. The assets and liabilities purchased were primarily working capital and we recorded goodwill of $12 million.

6. DEFERRED CHARGES AND OTHER ASSETS

	2008	2007
Crude Oil Put Options and Natural Gas Swaps (Note 7b)	234	1
Long-Term Energy Marketing Derivative Contracts (Note 7a)	217	248
Long-Term Capital Prepayments	61	9
Asset Retirement Remediation Fund	9	13
Other	49	53
Total	**570**	**324**

7. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments including accounts receivable, accounts payable, income taxes payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt are carried at cost or amortized cost. The carrying value of our short-term receivables and payables approximates their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities, and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The fair values are included with amounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income.

We carry our long-term debt at amortized cost using the effective interest rate method. At December 31, 2008, the estimated fair value of our long-term debt was $5,686 million (December 31, 2007—$4,692 million) as compared to the carrying value of $6,578 million (December 31, 2007—$4,610 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers. The recent economic crisis impacted market prices for corporate bonds and as a result, the estimated fair value of our long-term debt was lower in the fourth quarter of 2008.

Derivatives

(a) Total carrying value of derivative contracts related to trading activities

The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	2008	2007
Accounts Receivable	755	334
Deferred Charges and Other Assets [1]	217	248
Total Trading Derivative Assets	**972**	**582**
Accounts Payable and Accrued Liabilities	615	413
Deferred Credits and Other Liabilities [1]	294	163
Total Trading Derivative Liabilities	**909**	**576**
Total Net Trading Derivative Assets [2]	**63**	**6**

1 *These derivative contracts settle beyond 12 months and are considered non-current.*

2 *Comprised of $122 million (2007—$15 million) related to commodity contracts and net losses of $59 million (2007—$9 million loss) related to US-dollar and Euro forward contracts and swaps.*

(b) Total carrying value of derivative contracts related to non-trading activities

The fair value and carrying amounts related to derivative instruments related to non-trading activities are as follows:

	2008	2007
Accounts Receivable	6	–
Deferred Charges and Other Assets [1]	234	1
Total Non-Trading Derivative Assets	**240**	**1**
Accounts Payable and Accrued Liabilities	21	28
Deferred Credits and Other Liabilities [1]	26	51
Total Non-Trading Derivative Liabilities	**47**	**79**
Total Net Non-Trading Derivatives Assets (Liabilities)	**193**	**(78)**

1 *These derivative contracts settle beyond 12 months and are considered non-current.*

Crude oil put options

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production for $14 million. These options establish an annual average Dated Brent floor price of US$60/bbl on these volumes. In September 2008, Lehman Brothers filed for bankruptcy protection. This impacts 25,000 bbls/d of our 2009 put options and the carrying value of these put options has been reduced to nil.

In 2007, we purchased put options on approximately 100,000 bbls/d of our 2008 crude oil production for $24 million. These options established an annual average Dated Brent floor price of US$50/bbl on these volumes. These put options expired out of the money.

The crude oil put options are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Fair value of the put options is supported by multiple quotes obtained from third-party brokers, which were validated with observable market data to the extent possible. Any change in fair value is included in marketing and other income.

	Notional Volumes (bbls/d)	**Term**	**Average Floor Price** (US$/bbl)	**Fair Value** (Cdn$ millions)
Dated Brent Crude Oil Put Options	45,000	2009	60	233
Dated Brent Crude Oil Put Options	25,000	2009	60	–

Fixed-price natural gas contracts and natural gas swaps

We have fixed-price natural gas sales contracts and offsetting natural gas swaps that are not part of our trading activities. These sales contracts and swaps are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Any change in fair value is included in marketing and other income.

	Notional Volumes (Gj/d)	Term	Average Floor Price ($/Gj)	Fair Value (Cdn$ millions)
Fixed-Price Natural Gas Contracts	15,514	2009	2.28	(21)
	15,514	2010	2.28	(26)
Natural Gas Swaps	15,514	2009	7.60	6
	15,514	2010	7.60	1
				(40)

(c) Fair value of derivatives

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices, and if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated, or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

As a basis for establishing fair value, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net short position and the bid price when we have a net long position. This adjustment reflects an estimated exit price and incorporates the impact of liquidity when the bid-ask spread widens in less liquid markets. We incorporate the credit risk associated with counterparty default, as well as our own credit risk, into our estimates of fair value.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those which have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs which are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

The following table includes our derivatives that are carried at fair value for our trading and non-trading activities as at December 31, 2008. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

Net Derivatives	Level 1	Level 2	Level 3	Total
Trading Derivatives	13	132	(82)	63
Non-Trading Derivatives	–	193	–	193
Total	**13**	**325**	**(82)**	**256**

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the year ended December 31, 2008 is provided below:

	Level 3
Beginning of Year	(7)
Realized and unrealized gains (losses)	(64)
Purchases, issuances and settlements	(9)
Transfers in and/or out of Level 3	(2)
End of Year	**(82)**
Unsettled gains (losses) relating to instruments still held as of December 31, 2008	16

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

8. RISK MANAGEMENT

(a) Market risk

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage these market risk exposures.

The following market risk discussion relates primarily to commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes also may affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of near-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on providing services to our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities in selected regions of the world including crude oil, natural gas, electricity and other commodities. We do this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers.

In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial

derivative contracts including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

We also seek to profit from our views on the future movement of energy commodity pricing relationships, primarily between different locations, time periods or qualities. We do this by holding open positions, where the terms of physical or financial contracts are not completely matched to offsetting positions. We may also carry exposures to the absolute change in commodity prices based on our market views or as a consequence of managing our physical and financial positions on a day to day basis.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two day holding period in our measure, although actual results can differ from this estimate in non-normal market conditions, or if positions are held longer than two days based on market views or a lack of market liquidity to exit them, which is typical for long-term assets and may apply to nearer term positions. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available, and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" (for natural gas since May 2006) distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor our positions against these VaR limits daily. Our year end, annual high, annual low and average VaR amounts are as follows:

Value-at-Risk *(Cdn$ millions)*	**2008**	**2007**
Year End	25	26
High	40	38
Low	19	24
Average	30	30

If market shock occurred as in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of non-normal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

In our oil and gas operations, we manage our exposure to fluctuations between the US and Canadian dollar by maintaining our expected net cash flows and borrowings in the same currency. Cash inflows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. At December 31, 2008, we had US$5,432 million of long-term debt issued in US dollars and a one cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $52 million, before income tax.

We also have exposures to currencies other than the US dollar including a portion of our UK operating expenses, capital spending and future asset retirement obligations which are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies including Canadian and US dollars, British pounds and Euros. We actively manage significant currency exposures using forward contracts and swaps.

(b) Credit risk

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Approximately 71% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a rigorous credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the board;
- set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. During 2008, we have taken the following specific actions for certain counterparties deemed to be at higher risk of non-performance:

- ceased trading activities;
- significantly reduced and, in some cases, revoked credit privileges;
- redirected business to i) exchanges or clearing houses; and ii) entities with physical-based operations;
- increased "set off" arrangements with counterparties; and
- increased collateral and margining requirements where possible.

At December 31, 2008, only one counterparty individually made up more than 10% of our credit exposure. This counterparty is a major integrated oil company with a strong investment grade rating. No other counterparties made up more than 5% of our credit exposure. The following table illustrates the composition of credit exposure by credit rating.

Credit Rating	2008	2007
A or higher	65%	68%
BBB	29%	27%
Non-Investment Grade	6%	5%
Total	**100%**	**100%**

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as accounts receivable, cash and cash equivalents, restricted cash, as well as the fair value of derivative financial assets. In September 2008, Lehman Brothers filed for bankruptcy protection and our exposure at the time was approximately $39 million. This amount was provided for even though we continue to pursue recovery. We also provided an additional $15 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at December 31, 2008 includes $90 million of cash and $311 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

(c) Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due, and to operate in our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At December 31, 2008, we had about $4.5 billion of cash and available committed lines of credit (US$3.7 billion). This includes $2 billion of cash and cash equivalents on hand. Of this amount, approximately US$1 billion was a result of draws made on our term credit facilities, which were used for an internal reorganization and financing of our North Sea assets. In addition, we have undrawn term credit facilities of $2.5 billion (US$2.1 billion), of which $381 million (US$311 million) was supporting letters of credit at December 31, 2008. These facilities are available until 2012. We also have $613 million (US$501 million) of undrawn, uncommitted credit facilities, of which $29 million (US$24 million)

was supporting letters of credit at year end. Subsequent to year end, we used $735 million of our available liquidity to acquire an additional 15% interest in the Long Lake Project.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2008:

	Total	< 1 Year	1–3 Years	4–5 Years	> 5 Years
Long-Term Debt	6,652	–	223	1,898	4,531
Interest on Long-Term Debt [1]	7,611	331	662	657	5,961
Total	**14,263**	**331**	**885**	**2,555**	**10,492**

1 *Excludes interest on term credit facilities of $3.7 billion (US$3.1 billion) and Canexus term credit facilities of $420 million (US$343 million) as the amounts drawn on the facilities fluctuate. Based on amounts drawn at December 31, 2008 and existing variable interest rates, we would be required to pay $19 million per year until the outstanding amounts on the term credit facilities are repaid.*

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

	Total	< 1 Year	1–3 Years	4–5 Years	> 5 Years
Trading Derivatives	909	615	264	25	5
Non-Trading Derivatives	47	21	26	–	–
Total	**956**	**636**	**290**	**25**	**5**

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. Based on contracts in place and commodity prices at December 31, 2008, we could be required to post collateral of up to $1.3 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. In the event of a ratings downgrade, we have trading inventories and receivables that can be quickly monetized as well as significant undrawn credit facilities.

At December 31, 2008, collateral we have posted with counterparties includes $60 million of cash and $194 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. If there is a default, the cash is retained.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of $103 million (December 31, 2007—$203 million), which have been included in restricted cash.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2008	2007
Accrued Payables	2,033	2,546
Energy Marketing Derivative Contracts (Note 7a)	615	413
Trade Payables	303	578
Stock-based Compensation	97	393
Income Taxes Payable	69	45
Other	209	205
Total	**3,326**	**4,180**

10. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

	2008	2007
Medium-Term Notes, due 2008 (a)	–	125
Canexus Term Credit Facilities, due 2011 (US$182 million drawn) (b)	223	202
Term Credit Facilities, due 2012 (US$1 billion drawn) (c)	1,225	211
Canexus Notes, due 2013 (US$50 million) (d)	61	–
Notes, due 2013 (US$500 million) (e)	612	494
Notes, due 2015 (US$250 million) (f)	306	247
Notes, due 2017 (US$250 million) (g)	306	247
Notes, due 2028 (US$200 million) (h)	245	198
Notes, due 2032 (US$500 million) (i)	612	494
Notes, due 2035 (US$790 million) (j)	968	781
Notes, due 2037 (US$1,250 million) (k)	1,531	1,235
Subordinated Debentures, due 2043 (US$460 million) (l)	563	454
	6,652	**4,688**
Unamortized Debt Issue Costs	(74)	(78)
Total	**6,578**	**4,610**

(a) Medium-term notes, due 2008

During October 1997, we issued $125 million of notes with interest payable semi-annually at a rate of 6.3%. The principal of $125 million was repaid in full in June 2008.

(b) Canexus term credit facilities

Canexus has $420 million (US$343 million) of committed, secured term credit facilities, available until 2011. At December 31, 2008, $223 million (US$182 million) was drawn on these facilities (2007—$202 million (US$204 million)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at floating rates. The term credit facilities are secured by a floating charge debenture over all of Canexus' assets. The credit facility also contains covenants with respect to certain financial ratios for Canexus. During 2008, the weighted-average interest rate on the Canexus term credit facilities was 4.4% (2007—6.1%).

(c) Term credit facilities

We have unsecured term credit facilities of $3.7 billion (US$3.1 billion), available until 2012. At December 31, 2008, $1.2 billion (US$1 billion) was drawn on these facilities (2007—$211 million (US$214 million)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During 2008, the weighted-average interest rate was 2.8% (2007—5.8%). At December 31, 2008, $381 million (US$311 million) of these facilities were utilized to support outstanding letters of credit (December 31, 2007—$283 million (US$286 million)).

(d) Canexus Notes, due 2013

During the second quarter of 2008, Canexus issued US$50 million of notes. Interest is payable quarterly at a rate of 6.57% and the principal is to be repaid in May 2013. Canexus may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(e) Notes, due 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05%, and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(f) Notes, due 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.2%, and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.15%.

(g) Notes, due 2017

During May 2007, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.65%, and the principal is to be repaid in May 2017. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(h) Notes, due 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4%, and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.25%.

(i) Notes, due 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875%, and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.375%.

(j) Notes, due 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875%, and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(k) Notes, due 2037

During May 2007, we issued US$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4%, and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.35%.

(l) Subordinated debentures, due 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(m) Long-term debt repayments

2009	–
2010	–
2011	223 [1]
2012	1,225
2013	673
Thereafter	4,531
Total	**6,652**

1 *Canexus term credit facility.*

(n) Debt covenants

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2008 and 2007, we were in compliance with all covenants.

(o) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $613 million (US$501 million), none of which were drawn at December 31, 2008 (2007—$nil). We utilized $29 million (US$24 million) of these facilities to support outstanding letters of credit at December 31, 2008 (2007—$196 million (US$198 million)). Interest is payable at floating rates. During 2008, the weighted-average interest rate on our short-term borrowings was 3.2% (2007—5.8%).

(p) Interest expense

	2008	2007	2006
Long-Term Debt	315	323	275
Other	19	18	19
Total	334	341	294
Less: Capitalized	(240)	(173)	(241)
Total	**94**	**168**	**53**

Capitalized interest relates to and is included as part of the cost of oil and gas and Syncrude properties. The capitalization rates are based on our weighted-average cost of borrowings.

11. CAPITAL DISCLOSURE

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects which require significant capital investment prior to cash flow generation and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on the timing of expected net cash flows in a particular development or commodity cycle. This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

- maintaining an appropriate balance between short-term borrowings, long-term debt and shareholders' equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room permitting us to draw on credit lines as required; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to make adjustments to our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of shareholders' equity, short-term borrowings, long-term debt, and cash and cash equivalents as follows:

Net Debt [1]	**2008**	**2007**
Long-Term Debt	6,578	4,610
Less: Cash and Cash Equivalents	(2,003)	(206)
Total	**4,575**	**4,404**
Shareholders' Equity	**7,139**	**5,610**

1 Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

We monitor the leverage in our capital structure by reviewing the ratio of net debt to cash flow from operating activities and interest coverage ratios at various commodity prices.

We use the ratio of net debt to cash flow from operating activities as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is a non-GAAP measure that does not have any standard meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the twelve months ended December 31, 2008, our net debt to cash flow from operating activities ratio was 1.1 times compared to 1.6 times at December 31, 2007. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio allows us to monitor our ability to fund the interest requirements associated with our debt. Our interest coverage strengthened in 2008 from 12.1 times at the end of 2007 to 15.6 times at December 31, 2008.

Interest coverage is calculated by dividing our twelve-month trailing earnings before interest, taxes, DD&A (EBITDA) by interest expense before capitalized interest. EBITDA is a non-GAAP measure which is calculated using net income excluding interest expense, provision for income taxes, exploration expenses, DD&A, impairment and other non-cash expenses. The calculation of EBITDA is set out in the following table.

	2008	2007
Net Income	1,715	1,086
Add:		
Interest Expense	94	168
Provision for Income Taxes	1,457	792
Depreciation, Depletion, Amortization and Impairment	2,014	1,767
Exploration Expense	402	326
Recovery of Non-Cash Stock-Based Compensation	(272)	(109)
Change in Fair Value of Crude Oil Put Options	(203)	43
Other Non-Cash Expenses	(1)	14
EBITDA	**5,206**	**4,087**

12. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

	2008	2007
Asset Retirement Obligations, Beginning of Year	832	704
Obligations Incurred with Development Activities	32	105
Obligations Settled	(45)	(23)
Accretion Expense	58	44
Revisions to Estimates	159	79
Effects of Changes in Foreign Exchange Rate	23	(77)
End of Year [1, 2]	**1,059**	**832**

1 Obligations due within twelve months of $35 million (2007—$40 million) have been included in accounts payable and accrued liabilities.

2 Obligations relating to our oil and gas activities amount to $1,009 million (2007—$786 million) and obligations relating to our chemicals business amount to $50 million (2007—$46 million).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,393 million (2007—$2,165 million). We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 5.9% (2007—5.9%). Approximately $409 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

13. DEFERRED CREDITS AND OTHER LIABILITIES

	2008	2007
Deferred Tax Credit	709	–
Long-Term Marketing Derivative Contracts (Note 7a)	294	163
Deferred Transportation Revenue	69	82
Fixed-Price Natural Gas Contracts and Swaps (Note 7b)	26	51
Defined Benefit Pension Obligations (Note 14)	67	57
Capital Lease Obligations	53	52
Other	106	54
Total	**1,324**	**459**

During the third quarter of 2008, we completed an internal reorganization and financing of our assets in the North Sea which provided us with an additional one-time tax deduction in the UK. As these transactions were completed within our consolidated group, we are unable to recognize the benefit of the tax deductions until the assets are recognized in income by way of a sale to a third party or depletion through use. Accordingly, we have deferred recognizing $709 million of tax deductions in our consolidated income statement.

14. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen and Canexus have contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs, which cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan.

(a) Defined benefit pension plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2008			2007		
	Nexen	**Canexus**	**Syncrude**	**Nexen**	**Canexus**	**Syncrude**
Change in Projected Benefit Obligation (PBO)						
Beginning of Year	272	62	125	252	58	116
Service Cost	23	4	4	18	3	5
Interest Cost	17	4	7	13	3	6
Plan Participants' Contributions	5	1	1	4	1	1
Actuarial Loss/(Gain)	(39)	(11)	(25)	(2)	(3)	1
Benefits Paid	(13)	(1)	(5)	(13)	–	(4)
End of Year [1]	**265**	**59**	**107**	**272**	**62**	**125**
Change in Fair Value of Plan Assets						
Beginning of Year	200	55	74	185	50	69
Actual Return on Plan Assets	(54)	(9)	(19)	18	1	2
Employer's Contribution	15	4	6	6	3	6
Plan Participants' Contributions	5	1	1	4	1	1
Benefits Paid	(13)	(1)	(5)	(13)	–	(4)
End of Year	**153**	**50**	**57**	**200**	**55**	**74**
Reconciliation of Funded Status						
Funded Status [2]	(112)	(9)	(50)	(72)	(7)	(51)
Unamortized Transitional Obligation	–	–	–	–	–	–
Unamortized Prior Service Costs	1	–	–	2	–	–
Unamortized Net Actuarial Loss	60	8	35	31	6	36
Pension Liability	**(51)**	**(1)**	**(15)**	**(39)**	**(1)**	**(15)**
Pension Liability						
Deferred Charges and Other Assets	2	–	–	4	–	–
Accounts Payable and Accrued Liabilities	(2)	–	–	(2)	–	–
Other Deferred Credits and Liabilities (Note 13)	(51)	(1)	(15)	(41)	(1)	(15)
Pension Liability	**(51)**	**(1)**	**(15)**	**(39)**	**(1)**	**(15)**
Assumptions (%)						
Accrued Benefit Obligation at December 31						
Discount Rate	6.50	6.50	6.50	5.25	5.25	5.25
Long-Term Rate of Employee Compensation Increase	4.00	4.00	5.00	4.00	4.00	5.00
Benefit Cost for Year Ended December 31 [3]						
Discount Rate	5.25	5.25	6.50	5.00	5.00	5.25
Long-Term Rate of Employee Compensation Increase	4.00	4.00	5.00	4.00	4.00	5.00
Long-Term Annual Rate of Return on Plan Assets [4]	7.00	6.50	8.50	7.00	6.50	8.50

1 *The accumulated benefit obligations (the projected benefit obligation (PBO) excluding future salary increases) of the Nexen and Canexus plans were $179 million and $46 million at December 31, 2008, respectively (2007—$182 million and $47 million, respectively). Nexen's supplemental pension plan's accumulated benefit obligation was $49 million at December 31, 2008 (2007—$48 million). Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $82 million at December 31, 2008 (2007—$92 million).*

2 *Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2008, the PBO for Nexen's supplemental benefits was $62 million (2007—$62 million) and $1 million for Canexus (2007—$1 million). The unfunded obligations for supplemental benefits are backed by irrevocable letters of credit. Subsequent to December 31, 2008, we contributed $46 million to Nexen's defined benefit pension plan to fund existing solvency deficiencies.*

3 *The measurement date is December 31, 2008.*

4 *The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.*

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2008	2007	2006
Nexen			
Cost of Benefits Earned by Employees	23	18	16
Interest Cost on Benefits Earned	17	13	12
Actual (Return) Loss on Plan Assets	54	(18)	(23)
Actuarial (Gains)/Losses	(39)	(2)	9
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	55	11	14
Difference Between Actual and Expected Return on Plan Assets	(71)	5	12
Difference Between Actual and Recognized Actuarial Losses	41	3	(7)
Difference Between Actual and Recognized Past Service Costs	1	1	1
Net Pension Expense	**26**	**20**	**20**
Canexus			
Cost of Benefits Earned by Employees	4	3	3
Interest Cost on Benefits Earned	4	3	3
Actual (Return) Loss on Plan Assets	9	(2)	(6)
Actuarial (Gains)/Losses	(11)	(3)	2
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	6	1	2
Difference Between Actual and Expected Return on Plan Assets	(13)	(1)	3
Difference Between Actual and Recognized Actuarial Gains	11	3	(2)
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	**4**	**3**	**3**
Syncrude [1]			
Cost of Benefits Earned by Employees	4	5	5
Interest Cost on Benefits Earned	7	6	5
Actual (Return) Loss on Plan Assets	19	(2)	(8)
Actuarial (Gains)/Losses	(25)	1	–
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	5	10	2
Difference Between Actual and Expected Return on Plan Assets	(26)	(4)	3
Difference Between Actual and Recognized Actuarial Losses	27	1	2
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	**6**	**7**	**7**
Total Net Pension Expense	**36**	**30**	**30**

1 *Nexen's share of Syncrude's plan.*

(b) Plan asset allocation at December 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committees of Nexen and Canexus. Nexen's and Canexus' investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's and Canexus' investment policies.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

(%)	Expected 2009	2008	2007
Nexen			
Equity Securities	65	55	64
Debt Securities	35	45	36
Total	**100**	**100**	**100**
Canexus			
Equity Securities	50	50	50
Debt Securities	50	50	50
Total	**100**	**100**	**100**
Syncrude			
Equity Securities	70	68	68
Debt Securities	30	32	32
Total	**100**	**100**	**100**

(c) Defined contribution pension plans

Under these plans, pension benefits are based on plan contributions. During 2008, Canadian pension expense for these plans was $7 million (2007—$6 million; 2006—$4 million). During 2008, US pension expense for these plans was $4 million (2007—$4 million; 2006—$4 million) and UK pension expense for these plans was $6 million (2007—$5 million; 2006—$4 million).

(d) Post-retirement benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependants. The present value of Nexen employees' future post-retirement benefits at December 31, 2008 was $15 million (2007—$10 million) and $2 million for Canexus (2007—$1 million).

(e) Employer funding contributions and benefit payments

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we make contributions on behalf of our employees and no further obligation exists. Our funding contributions for the defined benefit plans are:

	Expected 2009	2008	2007
Nexen [1]	58	15	6
Canexus	3	4	3
Syncrude	7	7	6
Total Defined Benefit Contributions	**68**	**26**	**15**

1 Nexen's defined benefit plan has a solvency deficiency of $46 million at December 31, 2008 and we funded this amount in February 2009.

Our most recent funding valuation was prepared as of June 30, 2008. Our next funding valuation is required by June 30, 2011. Canexus' most recent funding valuation was prepared as of December 31, 2007, and their next funding valuation is required by December 31, 2010. Syncrude's most recent funding valuation was prepared as of December 31, 2006, and their next funding valuation is December 31, 2009.

Our total benefit payments in 2008 were $13 million for Nexen (2007—$13 million). Our share of Syncrude's total benefit payments in 2008 was $5 million (2007—$4 million). Our estimated future payments are as follows:

	Defined Benefit			Other		
	Nexen	Canexus	Syncrude	Nexen	Canexus	Syncrude
2009	10	1	4	2	–	–
2010	11	1	4	2	–	–
2011	12	2	5	3	–	–
2012	13	2	5	3	–	–
2013	14	3	6	4	–	–
2014–2018	88	20	36	27	–	2

15. SHAREHOLDERS' EQUITY

(a) Authorized capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

(b) Issued common shares and dividends

(thousands of shares)	2008	2007	2006
Issued Common Shares, Beginning of Year	528,305	525,026	522,281
Issue of Common Shares for Cash			
Exercise of Tandem Options	1,911	2,257	1,693
Dividend Reinvestment Plan	871	523	552
Employee Flow-through Shares	499	499	500
Repurchased under Normal Course Issuer Bid	(12,137)	–	–
End of Year	**519,449**	**528,305**	**525,026**
Dividends Declared per Common Share ($/share)	**0.18**	**0.10**	**0.10**
Cash Consideration (Cdn$ millions)			
Exercise of Tandem Options	23	24	16
Dividend Reinvestment Plan	25	16	16
Employee Flow-through Shares	16	16	16
Total	**64**	**56**	**48**

During the year, 871,254 common shares were issued under the Dividend Reinvestment Plan leaving a balance of 3,603,841 common shares (2007—4,475,095; 2006—997,662) reserved for issuance at December 31, 2008. Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

During the year, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid to repurchase up to a maximum of 52,914,046 common shares between August 6, 2008 and August 5, 2009. Under this authorization, we repurchased and cancelled 12,136,900 common shares acquired on the open market through the TSX at an average price of $27.85 per common share, totalling $338 million. Of the amount paid, $22 million reduced the book value of our common shares and the excess of $316 million reduced retained earnings.

The following summarizes the purchase of equity securities in 2008.

Period	(a) Total number of shares purchased (thousands)	(b) Average price paid per share ($/Share)	(c) Total number of shares purchased as part of publicly announced plans or programs (thousands)	(d) Maximum number of shares that may yet to be purchased under the plans or programs (thousands)
August 6–31, 2008	6,200	$31.78	6,200	46,714
September 1–30, 2008	3,787	$27.22	3,787	42,927
October 1–31, 2008	1,094	$16.44	1,094	41,833
November 1–30, 2008	1,056	$18.92	1,056	40,777
December 1–31, 2008	–	–	–	40,777
Total	**12,137**	**$27.85**	**12,137**	

(c) Tandem options

We have granted tandem options to purchase common shares to directors, officers and employees. Each option permits the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price.

	2008		2007		2006	
(thousands of shares)	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)
Outstanding Options, Beginning of Year	27,403	20	30,485	17	30,629	14
Granted	3,534	19	4,007	28	4,802	32
Exercised for Stock	(1,911)	13	(2,257)	10	(1,693)	9
Surrendered for Cash	(3,839)	13	(4,414)	11	(3,043)	9
Cancelled	(552)	30	(418)	22	(210)	19
Expired	(13)	11	–	–	–	–
End of Year	**24,622**	**22**	**27,403**	**20**	**30,485**	**17**
Options Exercisable at End of Year	17,087	21	18,216	16	18,691	12
Common Shares Reserved for Issuance Under the Tandem Option Plan	27,429		29,430		32,470	

The range of exercise prices of options outstanding and exercisable at December 31, 2008 is as follows:

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Years to Expiry (years)	Number of Options (thousands)	Weighted Average Exercise Price ($/option)
$5.00 to $9.99	3,178	8	2	3,178	8
$10.00 to $14.99	4,429	13	1	4,429	13
$15.00 to $19.99	3,523	19	5	12	17
$20.00 to $24.99	10	23	2	10	23
$25.00 to $29.99	8,777	28	3	6,456	28
$30.00 to $34.99	4,640	32	3	2,982	32
$35.00 to $39.99	59	36	3	20	37
$40.00 to $44.99	6	40	4	–	–
Total	**24,622**			**17,087**	

(d) Stock appreciation rights

Our StARs plan entitles employees to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The following stock appreciation rights have been granted:

	2008		2007		2006	
(thousands of shares)	**StARs** (thousands)	**Weighted Average Exercise Price** ($/StAR)	**StARs** (thousands)	**Weighted Average Exercise Price** ($/StAR)	**StARs** (thousands)	**Weighted Average Exercise Price** ($/StAR)
Outstanding StARs, Beginning of Year	15,435	24	13,890	21	11,928	15
Granted	4,917	19	4,195	29	4,509	32
Exercised for Cash	(2,837)	15	(2,349)	12	(2,165)	10
Cancelled	(529)	31	(301)	26	(382)	19
Expired	–	–	–	–	–	–
End of Year	**16,986**	**25**	**15,435**	**24**	**13,890**	**21**
StARs Exercisable at End of Year	8,119	25	7,525	19	6,151	13

The range of exercise prices of StARs outstanding and exercisable at December 31, 2008 is as follows:

	Outstanding StARs			Exercisable StARs	
	Number of StARs (thousands)	**Weighted Average Exercise Price** ($/StAR)	**Weighted Average Years to Expiry** (years)	**Number of StARs** (thousands)	**Weighted Average Exercise Price** ($/StAR)
$5.00 to $9.99	138	8	2	138	8
$10.00 to $14.99	1,978	13	1	1,978	13
$15.00 to $19.99	4,866	19	5	33	17
$20.00 to $24.99	70	23	2	63	23
$25.00 to $29.99	5,340	28	3	3,149	28
$30.00 to $34.99	4,489	32	3	2,740	32
$35.00 to $39.99	77	37	4	18	37
$40.00 to $44.99	19	44	4	–	–
$45.00 to $49.99	9	47	4	–	–
Total	**16,986**			**8,119**	

16. COMMITMENTS, CONTINGENCIES AND GUARANTEES

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases and transportation, storage and drilling rig commitments as at December 31, 2008 comprise of the following:

	2009	2010	2011	2012	2013	Thereafter
Operating Leases	91	115	109	105	100	195
Transportation and Storage Commitments	379	235	176	150	117	204
Drilling Rig Commitments	408	442	455	329	130	10

We have a number of lawsuits and claims pending including income tax reassessments (see Note 18), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2008, total rental expense under operating leases was $59 million (2007—$53 million; 2006—$49 million).

From time to time, we enter into certain types of contracts that require us to indemnify parties against possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary, and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities, would not have a material adverse effect on our liquidity, financial condition or results of operations.

17. MARKETING AND OTHER INCOME

	2008	2007	2006
Marketing Revenue, Net	467	959	1,309
Business Interruption Insurance Proceeds [1]	–	–	154
Change in Fair Value of Crude Oil Put Options	203	(43)	(11)
Interest	28	39	36
Foreign Exchange Gains (Losses)	128	(22)	(72)
Gains on Disposition of Assets	3	2	4
Other	(16)	86	30
Total	**813**	**1,021**	**1,450**

1 *In 2006, we received business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005 and by generator failures in our UK operations in 2005.*

18. INCOME TAXES

(a) Temporary differences

	2008		2007	
	Future Income Tax Assets	**Future Income Tax Liabilities**	**Future Income Tax Assets [1]**	**Future Income Tax Liabilities**
Property, Plant and Equipment, Net	27	2,543	25	2,229
Tax Losses Carried Forward	300	–	256	–
Deferred Income	–	76	–	61
Recoverable Taxes	24	–	5	–
Total	**351**	**2,619**	**286**	**2,290**

1 *In 2007, future income tax assets of $18 million that we expected to realize in the following twelve months were included in other current assets.*

(b) Canadian and foreign income taxes

	2008	2007	2006
Income (Loss) before Income Taxes			
Canadian	(100)	(33)	(352)
Foreign	3,268	1,929	1,648
	3,168	1,896	1,296
Provision for Income Taxes			
Current			
Canadian	1	1	14
Foreign	858	433	354
	859	434	368
Future			
Canadian	22	12	(96)
Foreign	576	346	411
	598	358	315
Total	**1,457**	**792**	**683**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, Colombia, the UK, the US and Norway.

(c) Reconciliation of effective tax rate to the Canadian statutory tax rate

	2008	2007	2006
Income before Provision for Income Taxes	3,168	1,896	1,296
Provision for Income Taxes Computed at the Canadian Statutory Rate	893	537	401
Add (Deduct) the Tax Effect of:			
Royalties, Rentals and Similar Payments to Provincial Governments	–	–	15
Resource Allowance and Provincial Tax Rebates	–	–	(15)
Foreign Tax Rate Differential	525	233	(9)
Additional Canadian Tax on Canadian Resource Income	–	–	10
Higher (Lower) Tax Rates on Capital Gains	9	(5)	(3)
Federal and Provincial Capital Tax	2	1	13
Effect of Changes in Tax Rates	–	(15)	245
Non-Deductible Expenses and Other	28	41	26
Provision for Income Taxes	**1,457**	**792**	**683**
Effective Tax Rate	**46%**	**42%**	**53%**

During the first quarter of 2006, we recorded a future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom. The United Kingdom parliament increased the supplemental tax rate from 10% to 20%, effective January 1, 2006.

In 2007 and 2006, the federal government and some provincial governments in Canada reduced statutory corporate income tax rates. This reduced our liability and provision for future income taxes by $15 million in 2007 and $32 million in 2006.

(d) Available unused tax losses and tax contingencies

At December 31, 2008, we had unused tax losses totalling $954 million (2007—$820 million; 2006—$1,258 million). The majority of these losses are in Canada and the US and will expire between 2016 and 2028.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an appropriate provision for income taxes based on available information.

19. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2008	2007	2006
Weighted-Average Number of Common Shares, Basic	526.1	527.1	524.2
Shares Issuable Pursuant to Tandem Options	18.8	26.6	27.7
Shares to be Notionally Purchased from Proceeds of Tandem Options	(12.7)	(15.7)	(14.0)
Weighted-Average Number of Common Shares, Diluted	**532.2**	**538.0**	**537.9**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2008, we excluded 5,694,055 tandem options (2007—49,333; 2006—422,566), because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding tandem options were the only potential dilutive instruments.

20. CASH FLOWS

(a) Charges and credits to income not involving cash

	2008	2007	2006
Depreciation, Depletion, Amortization and Impairment	2,014	1,767	1,124
Stock-Based Compensation	(272)	(109)	101
Gains on Disposition of Assets	(3)	(2)	(4)
Provision for Future Income Taxes	598	358	315
Change in Fair Value of Crude Oil Put Options	(203)	43	11
Net (Loss) Income Attributable to Non-Controlling Interests	(4)	18	12
Other	6	(2)	70
Total	**2,136**	**2,073**	**1,629**

(b) Changes in non-cash working capital

	2008	2007	2006
Accounts Receivable	950	(797)	345
Inventories and Supplies	246	(97)	(302)
Other Current Assets	5	(15)	(14)
Accounts Payable and Accrued Liabilities	(1,232)	691	(72)
Other	26	–	–
Total	**(5)**	**(218)**	**(43)**
Relating to:			
Operating Activities	119	(348)	(177)
Investing Activities	(124)	130	134
Total	**(5)**	**(218)**	**(43)**

(c) Other cash flow information

	2008	2007	2006
Interest Paid	319	328	278
Income Taxes Paid	1,055	408	398

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $137 million (2007—$123 million; 2006—$128 million).

21. SUBSEQUENT EVENT

In January 2009, we completed the acquisition of an additional 15% interest in the Long Lake Project and the joint venture lands for $735 million.

22. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in Colombia, offshore West Africa and Norway.

Energy Marketing: Our energy marketing group sells our crude oil and natural gas, markets third-party crude oil, natural gas, NGLs and power (including electricity generation) and engages in energy trading.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from mining bitumen in the Athabasca oil sands in northern Alberta.

Chemicals: Through our investment in Canexus, we manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. We produce sodium chlorate at four facilities in Canada and one in Brazil. We produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses with the exception of Chemicals. Identifiable assets are those used in the operations of the segments.

2008 Operating and Geographic Segments

	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
(Cdn$ millions)	Yemen	Canada	US	UK	Other Countries[1]					
Net Sales[2]	1,093	656	665	3,580	192	70	691	477[3]	–	7,424
Marketing and Other	12	3	4	5	–	467	6	(50)	366[4]	813
	1,105	659	669	3,585	192	537	697	427	366	8,237
Less: Expenses										
Operating	176	182	94	253	10	43	280	297	–	1,335
Depreciation, Depletion, Amortization and Impairment[5]	160	208	475	999	17	19	49	44	43	2,014
Transportation and Other	9	12	3	19	–	805	16	55	48	967
General and Administrative[6]	(7)	20	38	(8)	13	79	1	33	88	257
Exploration	5	79	109	86	123[7]	–	–	–	–	402
Interest	–	–	–	–	–	–	–	12	82	94
Income (Loss) before Income Taxes	762	158	(50)	2,236	29	(409)	351	(14)	105	3,168
Less: Provision for (Recovery of) Income Taxes[8]	264	45	(19)	1,126	(4)	(102)	99	2	46	1,457
Net Income (Loss)	498	113	(31)	1,110	33	(307)	252	(16)	59	1,711
Non-Controlling Interests	–	–	–	–	–	–	–	(4)	–	(4)
Net Income (Loss)	**498**	**113**	**(31)**	**1,110**	**33**	**(307)**	**252**	**(12)**	**59**	**1,715**
Identifiable Assets	**342**	**6,643[9]**	**2,044**	**6,632**	**701**	**3,280[10]**	**1,198**	**573**	**742**	**22,155**
Capital Expenditures										
Development and Other	92	1,180	251	545	190	8	55	88	53	2,462
Exploration	9	225	154	146	48	–	–	–	–	582
Proved Property Acquisitions	–	22	–	–	–	–	–	–	–	22
Total	**101**	**1,427**	**405**	**691**	**238**	**8**	**55**	**88**	**53**	**3,066**
PP&E										
Cost	2,808	8,134	4,398	6,532	554	246	1,372	940	331	25,315
Less: Accumulated DD&A	2,610	1,786	2,702	2,159	113	76	236	507	204	10,393
Net Book Value[2]	**198**	**6,348[9]**	**1,696**	**4,373**	**441**	**170**	**1,136**	**433**	**127**	**14,922**
Goodwill	**–**	**–**	**–**	**341**	**–**	**49**	**–**	**–**	**–**	**390**

1 Includes results of operations from producing activities in Colombia.

2 Net sales made from all segments originating in Canada: 1,570
PP&E located in Canada: 8,121

3 Net sales for our chemicals operations include:

Canada	*153*
US	*214*
Brazil	*110*
Total	***477***

4 Includes interest income of $28 million, foreign exchange gains of $128 million, increase in the fair value of crude oil put options of $203 million and other income of $7 million.

5 Includes an impairment charge related to oil and gas properties in the UK North Sea and the US Gulf of Mexico of $318 million and $250 million, respectively.

6 Includes recovery of stock-based compensation expense of $160 million.

7 Includes exploration activities primarily in Norway and Colombia.

8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

9 Includes costs of $4,742 million related to our insitu oil sands (Long Lake and future phases).

10 79% of Marketing's identifiable assets are accounts receivable and inventories.

2007 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: Yemen	Canada	US	UK	Other Countries [1]	Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
Net Sales [2]	1,086	441	616	2,285	148	48	545	414 [3]	–	5,583
Marketing and Other	10	6	–	39	–	959	–	33	(26) [4]	1,021
	1,096	447	616	2,324	148	1,007	545	447	(26)	6,604
Less: Expenses										
Operating	171	173	102	212	8	34	208	257	–	1,165
Depreciation, Depletion, Amortization and Impairment	213	166	641 [5]	599	8	13	53	45	29	1,767
Transportation and Other	8	22	–	–	–	806	17	39	16	908
General and Administrative [6]	(6)	50	38	3	40	87	1	31	130	374
Exploration	5	27	134	69	91 [7]	–	–	–	–	326
Interest	–	–	–	–	–	–	–	11	157	168
Income (Loss) before Income Taxes	705	9	(299)	1,441	1	67	266	64	(358)	1,896
Less: Provision for (Recovery of) Income Taxes [8]	248	3	(103)	712	–	21	75	18	(182)	792
Net Income (Loss)	457	6	(196)	729	1	46	191	46	(176)	1,104
Non-Controlling Interests	–	–	–	–	–	–	–	18	–	18
Net Income (Loss)	**457**	**6**	**(196)**	**729**	**1**	**46**	**191**	**28**	**(176)**	**1,086**
Identifiable Assets	**359**	**5,379 [9]**	**1,640**	**4,642**	**317**	**3,663 [10]**	**1,212**	**487**	**376**	**18,075**
Capital Expenditures										
Development and Other	124	1,381	414	551	53	4	36	62	52	2,677
Exploration	12	123	275	119	44	–	–	–	–	573
Proved Property Acquisitions	–	1	104 [11]	46 [12]	–	–	–	–	–	151
Total	**136**	**1,505**	**793**	**716**	**97**	**4**	**36**	**62**	**52**	**3,401**
PP&E										
Cost	2,178	6,736	3,069	4,723	263	246	1,332	831	315	19,693
Less: Accumulated DD&A	1,950	1,597	1,765	908	77	62	205	463	168	7,195
Net Book Value [2]	**228**	**5,139 [9]**	**1,304**	**3,815**	**186**	**184**	**1,127**	**368**	**147**	**12,498**
Goodwill	**–**	**–**	**–**	**276**	**–**	**50**	**–**	**–**	**–**	**326**

1 Includes results of operations from producing activities in Colombia.
2 Net sales made from all segments originating in Canada: 1,188
PP&E located in Canada: 6,893
3 Net sales for our chemicals operations include:

Canada	*154*
US	*169*
Brazil	*91*
Total	***414***

4 Includes interest income of $39 million, foreign exchange losses of $22 million and decrease in the fair value of crude oil put options of $43 million.
5 Includes an impairment charge of $366 million related to oil and gas properties in the Gulf of Mexico.
6 Includes stock-based compensation expense of $38 million.
7 Includes exploration activities primarily in Nigeria, Norway and Colombia.
8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
9 Includes costs of $3,695 million related to our insitu oil sands (Long Lake and future phases).
10 84% of Marketing's identifiable assets are accounts receivable and inventories.
11 Includes acquisition of producing properties in the Gulf of Mexico.
12 Includes acquisition of additional interests in the Scott and Telford fields.

2006 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	US	UK	Other Countries [1]					
Net Sales [2]	1,328	459	629	477	139	51	446	407 [3]	–	3,936
Marketing and Other	8	7	81 [4]	85 [5]	1	1,309	–	6	(47) [6]	1,450
	1,336	466	710	562	140	1,360	446	413	(47)	5,386
Less: Expenses										
Operating	151	143	106	80	8	31	187	249	–	955
Depreciation, Depletion, Amortization and Impairment [7]	327	162	296	216	10	12	33	40	28	1,124
Transportation and Other	6	33	–	–	1	789	18	40	154 [8]	1,041
General and Administrative [9]	17	80	58	14	44	112	1	29	200	555
Exploration	4	26	214	46	72 [10]	–	–	–	–	362
Interest	–	–	–	–	–	–	–	11	42	53
Income (Loss) before Income Taxes	831	22	36	206	5	416	207	44	(471)	1,296
Less: Provision for (Recovery of) Income Taxes [11]	289	7	13	378 [12]	1	151	66	15	(237)	683
Net Income (Loss)	542	15	23	(172)	4	265	141	29	(234)	613
Non-Controlling Interests	–	–	–	–	–	–	–	12	–	12
Net Income (Loss)	**542**	**15**	**23**	**(172)**	**4**	**265**	**141**	**17**	**(234)**	**601**
Identifiable Assets	**464**	**3,923 [13]**	**1,620**	**5,490**	**245**	**3,528 [14]**	**1,186**	**459**	**241**	**17,156**
Capital Expenditures										
Development and Other	145	1,434	418	596	28	47	86	27	45	2,826
Exploration	37	163	177	62	52	–	–	–	–	491
Proved Property Acquisitions	–	12	–	1	–	–	–	–	–	13
Total	**182**	**1,609**	**595**	**659**	**80**	**47**	**86**	**27**	**45**	**3,330**
PP&E										
Cost	2,404	5,216	2,889	4,710	249	226	1,304	854	286	18,138
Less: Accumulated DD&A	2,128	1,448	1,445	432	78	47	179	494	148	6,399
Net Book Value [2]	**276**	**3,768 [13]**	**1,444**	**4,278**	**171**	**179**	**1,125**	**360**	**138**	**11,739**
Goodwill	**–**	**–**	**–**	**325**	**–**	**52**	**–**	**–**	**–**	**377**

1 Includes results of operations from producing activities in Colombia.

2 Net sales made from all segments originating in Canada: 1,095
PP&E located in Canada: 5,483

3 Net sales for our chemicals operations include:

Canada	*139*
US	*185*
Brazil	*83*
Total	***407***

4 Includes $80 million of business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005.

5 Includes $74 million of business interruption insurance proceeds for generator failures in 2005.

6 Includes interest income of $36 million, foreign exchange losses of $72 million and decrease in the fair value of crude oil put options of $11 million.

7 Includes an impairment charge of $93 million, primarily relating to two natural gas properties in the Gulf of Mexico.

8 Includes $151 million (US$135 million) accrual with respect to the Block 51 arbitration settlement.

9 Includes stock-based compensation expense of $210 million.

10 Includes exploration activities primarily in Nigeria, Norway and Colombia.

11 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

12 Includes future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom (see Note 18).

13 Includes costs of $2,444 million related to our insitu oil sands (Long Lake and future phases).

14 80% of Marketing's identifiable assets are accounts receivable and inventories.

23. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP
For the Three Years ended December 31, 2008

(Cdn$ millions, except per share amounts)	2008	2007	2006
Revenues and Other Income			
Net Sales	7,424	5,583	3,936
Marketing and Other (i); (vi); (vii)	796	938	1,459
	8,220	6,521	5,395
Expenses			
Operating (ii)	1,335	1,167	958
Depreciation, Depletion, Amortization and Impairment	2,014	1,767	1,124
Transportation and Other (vi)	964	906	1,037
General and Administrative (v)	263	401	597
Exploration	402	326	362
Interest	94	168	53
	5,072	4,735	4,131
Income before Provision for Income Taxes	3,148	1,786	1,264
Provision for Income Taxes			
Current	859	434	368
Deferred (i); (ii); (v); (vii)	589	322	305
	1,448	756	673
Net Income before Non-Controlling Interests	1,700	1,030	591
Net Income (Loss) Attributable to Non-Controlling Interests	(4)	18	12
Net Income—US GAAP [1]	**1,704**	**1,012**	**579**
Earnings Per Common Share ($/share) (Note 19)			
Basic	3.24	1.92	1.10
Diluted	3.20	1.88	1.08

1 Reconciliation of Canadian and US GAAP Net Income

(Cdn$ millions)	***2008***	***2007***	***2006***
Net Income—Canadian GAAP	*1,715*	*1,086*	*601*
Impact of US Principles, Net of Income Taxes:			
Ineffective Portion of Cash Flow Hedges (i)	*–*	*(2)*	*9*
Pre-operating Costs (ii)	*–*	*(1)*	*(2)*
Stock-based Compensation (v)	*(4)*	*(19)*	*(29)*
Inventory Valuation (vii)	*(7)*	*(52)*	*–*
Net Income—US GAAP	***1,704***	***1,012***	***579***

Consolidated Balance Sheet—US GAAP
December 31, 2008 and 2007

(Cdn$ millions, except share amounts)	2008	2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	2,003	206
Restricted Cash	103	203
Accounts Receivable	3,163	3,502
Inventories and Supplies (vii)	426	615
Other	169	89
Total Current Assets	5,864	4,615
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $10,786 (December 31, 2007—$7,588) (ii); (iv)	14,873	12,449
Goodwill	390	326
Deferred Income Tax Assets	351	268
Deferred Charges and Other Assets	570	324
TOTAL ASSETS	**22,048**	**17,982**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable and Accrued Liabilities (v)	3,384	4,233
Accrued Interest Payable	67	54
Dividends Payable	26	13
Total Current Liabilities	3,477	4,300
Long-Term Debt	6,578	4,610
Deferred Income Tax Liabilities (ii); (iii); (v); (vii); (viii)	2,543	2,230
Asset Retirement Obligations	1,024	792
Deferred Credits and Other Liabilities (iii)	1,428	534
Non-Controlling Interests	52	67
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2008—519,448,590 shares		
2007—528,304,813 shares	981	917
Contributed Surplus	2	3
Retained Earnings (i)–(v); (vii); (viii)	6,172	4,876
Accumulated Other Comprehensive Loss (i); (iii)	(209)	(347)
Total Shareholders' Equity	6,946	5,449
Commitments, Contingencies and Guarantees (Notes 16 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**22,048**	**17,982**

Consolidated Statement of Comprehensive Income—US GAAP
For the Three Years ended December 31, 2008

(Cdn$ millions)	2008	2007	2006
Net Income—US GAAP	1,704	1,012	579
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment	159	(132)	–
Change in Mark to Market on Cash Flow Hedges (i)	–	(61)	77
Minimum Unfunded Pension Liability (iii)	–	–	5
Unamortized Defined Benefit Pension Plan Costs (iii)	(21)	2	–
Comprehensive Income	**1,842**	**821**	**661**

Consolidated Statement of Accumulated Other Comprehensive Loss—US GAAP
December 31, 2008 and 2007

(Cdn$ millions)	2008	2007
Foreign Currency Translation Adjustment	(134)	(293)
Unamortized Defined Benefit Pension Plan Costs (iii)	(75)	(54)
Accumulated Other Comprehensive Loss (AOCL)	**(209)**	**(347)**

Notes to the Consolidated US GAAP Financial Statements:

i. Under US GAAP, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. On January 1, 2007, we adopted the equivalent Canadian standard for derivative instruments and hedging.

Future sale of gas inventory:

We use futures and swaps as cash flow hedges against the commodity price risk on the future sale of our gas inventory. Prior to January 1, 2007, we included the hedging derivative contracts on our US GAAP Consolidated Balance Sheet with the effective portion of gains or losses recognized in AOCI. The ineffective gain or loss was included in marketing and other within the US GAAP net income immediately.

In 2005, we recognized $11 million ($7 million, net of income taxes) of ineffective losses related to these hedges in our US GAAP net income. Under Canadian GAAP, these losses were recognized in 2006.

At December 31, 2006, we included $25 million of gains on these cash flow hedges in accounts receivable. AOCI includes the effective portion of $23 million ($16 million, net of income taxes) and $2 million ($2 million, net of income taxes) of the ineffective portion in our US GAAP net income. Under Canadian GAAP, these gains were recognized in 2007.

ii. Under Canadian GAAP, we defer certain development costs and all pre-operating revenues and costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:

- in 2008, operating expenses do not include any pre-operating costs (2007—$2 million ($1 million, net of income taxes); 2006—$3 million ($2 million, net of income taxes)); and
- PP&E is lower under US GAAP by $30 million (December 31, 2007—lower by $30 million) and deferred income tax liabilities is $11 million lower (December 31, 2007—lower by $11 million).

iii. On December 31, 2006, we adopted FASB Statement No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* for US GAAP. This requires, among other things, the recognition of the over-funded and under-funded status of a defined benefit plan on the balance sheet as an asset or liability. At year end, the unfunded amount of our defined benefit pension plans that was not included in the Pension Liability under Canadian GAAP was $104 million (2007—$75 million). This amount has been included in deferred credits and other liabilities and $75 million, net of income taxes (2007—$54 million, net of income taxes), has been included in AOCI. Prior to the adoption of FAS 158 on December 31, 2006, we included our minimum unfunded pension liability in our US GAAP Consolidated Balance Sheet.

iv. On January 1, 2003, we adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

v. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. In addition, under Canadian principles, we retroactively adopted EIC-162 which requires the accelerated recognition of stock-based compensation expense for all stock-based awards made to our retired and retirement-eligible employees. However, US GAAP requires the accelerated recognition of stock-based compensation expense for such employees for awards granted on or after January 1, 2006. As a result:

- general and administrative expense is higher by $6 million ($4 million, net of income taxes) for the year ended December 31, 2008 (2007—higher by $27 million ($19 million, net of income taxes); 2006—higher by $42 million ($29 million, net of income taxes)); and
- accounts payable and accrued liabilities are higher by $58 million at December 31, 2008 (2007—higher by $53 million) and deferred income tax liabilities are $17 million lower (2007—lower by $15 million).

vi. Under US GAAP, asset disposition gains and losses are included with transportation and other expense. Gains of $3 million were reclassified from marketing and other to transportation and other (2007—$2 million; 2006—$4 million).

vii. Under Canadian GAAP, we began carrying our commodity inventory held for trading purposes at fair value, less any costs to sell effective October 1, 2007. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result:

- marketing and other is lower by $14 million ($7 million, net of income taxes) for the year ended December 31, 2008 (2007 lower by $79 million, ($52 million net of income tax)); and
- inventories are lower by $58 million at December 31, 2008 (2007—lower by $44 million) and deferred income tax liabilities are $21 million lower (2007—lower by $14 million).

viii. On January 1, 2007, we adopted FASB Interpretation 48 *Accounting for Uncertainty in Income Taxes* (FIN 48) regarding accounting and disclosure for uncertain tax positions. On the adoption of FIN 48, we recorded a cumulative effect of a change in accounting principle of $28 million. This amount increased our deferred income tax liabilities and decreased our retained earnings as at January 1, 2007 in our US GAAP—Consolidated Balance Sheet.

As at December 31, 2008, the total amount of our unrecognized tax benefits was approximately $249 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Consolidated Statement of Income. As at December 31, 2008, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP—Consolidated Balance Sheet was approximately $9 million. We had no interest or penalties included in the US GAAP—Consolidated Statement of Income for the year ended December 31, 2008.

Our income tax filings are subject to audit by taxation authorities and as at December 31, 2008 the following tax years remained subject to examination, (i) Canada—1985 to date, (ii) United Kingdom—2007 to date and (iii) United States—2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next twelve months.

Reconciliation of Unrecognized Tax Benefits

(Cdn$ millions)	
Balance at January 1, 2008	221
Additions for tax positions related to the current year	9
Additions for tax positions related to prior years	55
Reductions for tax positions related to prior years	(36)
Balance at December 31, 2008	**249**

Stock-Based Compensation

On January 1, 2006, we adopted FASB Statement 123 (revised), *Share-Based Payment* (Statement 123(R)) using the modified prospective approach and graded vesting amortization. Under Statement 123(R), our tandem options and stock appreciation rights (StARs) are considered liability-based stock compensation plans. Under the modified prospective approach, no amounts are restated in prior periods. Upon adoption of Statement 123(R), we recorded a cumulative effect of a change in accounting principle of $2 million. This amount was recorded in general and administrative expenses in our US GAAP Consolidated Statement of Income in 2006.

Prior to the adoption of Statement 123(R), we accounted for our liability-based stock compensation plans in accordance with FASB Interpretation 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans (the intrinsic-value method). Accordingly, obligations were accrued on a graded vesting basis and represented the difference between the market value of our common shares and the exercise price of underlying options and rights. Under Statement 123(R), obligations for liability-based stock compensation plans are measured at their fair value and remeasured in each subsequent reporting period.

Consistent with Statement 123(R), we account for any stock options that do not include a cash feature (equity-based stock compensation plans) using the fair-value method.

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of our stock-based compensation, with the following assumptions:

Expected Annual Dividends per Common Share ($/share)	0.20
Expected Volatility	52%
Risk-Free Interest Rate	1.0%–1.6%
Weighted-Average Expected Life of Compensation Instruments (years)	2.9–3.2

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the implied volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds. Our valuation methodology and assumptions are consistent with those previously used under FAS 123.

Stock Options

	Number (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/option)
Outstanding at December 31, 2008	24,622	22	2.6	87	6
Outstanding at December 31, 2008 and Expected to Vest	24,388	22	2.6	86	6
Exercisable at December 31, 2008	17,087	21	1.9	80	6

The total intrinsic value of stock options exercised during the year ended December 31, 2008 was $88 million (2007—$149 million; 2006—$109 million). As at December 31, 2008, we had $34 million of unrecognized compensation expense related to stock options which we expect to recognize over a weighted-average period of 1.6 years.

Stock Appreciation Rights

	Number (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/right)
Outstanding at December 31, 2008	16,986	25	3.3	30	5
Outstanding at December 31, 2008 and Expected to Vest	16,558	25	3.3	29	5
Exercisable at December 31, 2008	8,119	25	2.3	19	4

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2008 was $52 million (2007—$50 million; 2006—$46 million). As at December 31, 2008, we had $42 million of unrecognized compensation expense related to stock appreciation rights which we expect to recognize over a weighted-average period of 1.6 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2008, stock-based compensation recovery of $154 million (2007—$65 million expense; 2006—$252 million expense) was included in general and administrative expense in the Consolidated Statement of Income—US GAAP.

For the year ended December 31, 2008, cash proceeds of $23 million were received related to the exercise of stock options (2007—$24 million; 2006—$16 million). For the year ended December 31, 2008, $121 million was paid related to the exercise of stock options and stock appreciation rights (2007—$149 million; 2006—$119 million). The income tax benefit recorded from the exercise of stock options and stock appreciation rights was $34 million (2007—$42 million; 2006—$37 million) for the period.

Stock-Based Compensation Expense for Retired and Retirement Eligible Employees

We recognize stock-based compensation expense for our retired and retirement-eligible employees over an accelerated graded vesting period in accordance with the provisions of Statement 123(R) for stock-based awards granted to employees on or after January 1, 2006. For stock-based awards granted prior to the adoption of Statement 123(R), stock-based compensation expense for our retired and retirement-eligible employees is recognized over a graded vesting period. If we applied the accelerated graded vesting provisions of Statement 123(R) to stock-based awards granted to our retired and retirement-eligible employees prior to the adoption of Statement 123(R), our stock-based compensation expense would decrease by $2 million for the year ended December 31, 2008 (2007—$9 million; 2006—$10 million).

Changes in Accounting Policies—US GAAP

Fair Value Measurements

On January 1, 2008, we adopted FASB Statement 157, *Fair Value Measurements* which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The adoption of this statement did not have a material impact on our results of operations or financial position. The additional disclosures required by the statement are included in Note 7.

Pension

Effective December 31, 2006, we adopted the recognition and disclosure provisions of FASB Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans*. This statement also requires measurement of the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. Effective December 31, 2008, we adopted the change in measurement date provision of FASB Statement 158. The funded status of our defined benefit pension plan is now as of the balance sheet date of December 31, 2008. The adoption of this change did not have a material impact on our results of operations or financial position.

New Accounting Pronouncements—US GAAP

In December 2007, FASB issued Statement 141 (revised), *Business Combinations*. Statement 141 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Non-controlling Interests In Consolidated Financial Statements,* an amendment of ARB No. 51. This statement clarifies that a non-controlling interest in a subsidiary should be reported as equity in the Consolidated Financial Statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In March 2008, FASB issued Statement 161, *Disclosures about Derivative Instruments and Hedging Activities,* an amendment of FASB Statement 133. The statement requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged position. The statement also requires the disclosure of the location and amounts of derivative instruments in the financial statements. This statement is effective for fiscal years and interim periods beginning on or after November 15, 2008. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2008, FASB issued FSP FAS 132 (R)-1, *Employers' Disclosures about Post-retirement Benefit Plan Assets* which provides guidance on disclosures about plan assets of a defined benefit pension or other post-retirement plans. This statement is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Quarterly Financial Data in Accordance with Canadian and US GAAP

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Net Sales	1,870	1,140	2,071	1,399	2,213	1,446	1,270	1,598
Income (Loss) before Income Taxes is Comprised of:								
Oil and Gas[1]	1,050	303	976	604	1,364	642	(255)	308
Energy Marketing	14	(4)	(183)	70	(79)	(4)	(161)	5
Syncrude	78	54	97	48	139	88	37	76
Chemicals	(4)	11	11	21	5	25	(26)	7
Corporate and Other	(38)	(145)	(208)	(93)	77	(63)	274	(57)
	1,100	**219**	**693**	**650**	**1,506**	**688**	**(131)**	**339**
Net Income (Loss)—Canadian GAAP	**630**	**121**	**380**	**368**	**886**	**403**	**(181)**	**194**
US GAAP Adjustments	(13)	(3)	(62)	(14)	120	(15)	(56)	(42)
Net Income (Loss)—US GAAP	**617**	**118**	**318**	**354**	**1,006**	**388**	**(237)**	**152**
Earnings (Loss) per Common Share ($/share)								
Canadian GAAP—Basic	1.19	0.23	0.72	0.70	1.68	0.77	(0.35)	0.37
Canadian GAAP—Diluted	1.17	0.22	0.70	0.68	1.66	0.75	(0.35)	0.36
US GAAP—Basic	1.17	0.22	0.60	0.67	1.91	0.74	(0.46)	0.29
US GAAP—Diluted	1.15	0.22	0.59	0.66	1.89	0.72	(0.46)	0.28
Dividends Declared[2]	0.025	0.025	0.050	0.025	0.050	0.025	0.050	0.025
Common Share Prices ($/share)								
Toronto Stock Exchange—High	34.20	37.60	43.45	36.51	41.47	36.32	29.10	32.63
Toronto Stock Exchange—Low	26.00	29.66	29.69	31.25	21.12	27.21	13.33	27.88
New York Stock Exchange—High (US$)	34.57	31.88	42.71	32.21	40.99	34.79	23.99	34.37
New York Stock Exchange—Low (US$)	25.11	25.18	28.87	29.08	20.56	25.25	10.81	27.58

1 *The fourth quarter of 2008 includes an impairment charge of $568 million relating to oil and gas properties in the US Gulf of Mexico and the UK North Sea. The fourth quarter of 2007 includes an impairment charge of $366 million relating to oil and gas properties in the Gulf of Mexico.*

2 *In February 2009, the Board of Directors declared a quarterly dividend of $0.05 per common share, payable April 1, 2009, to shareholders of record on March 10, 2009.*

3 *At December 31, 2008, there were 1,624 registered holders of common shares and 519,448,590 common shares outstanding.*

OIL AND GAS PRODUCING ACTIVITIES AND SYNCRUDE OPERATIONS (UNAUDITED)

The following oil and gas information is provided in accordance with the FASB Statement No. 69 *Disclosures about Oil and Gas Producing Activities*. It also includes information relating to our interest in Syncrude as it produces a crude oil product similar to our oil and gas activities even though these operations are considered mining activities under SEC regulations.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves for our conventional operations (excluding Syncrude) are disclosed below. The net proved reserves represent management's best estimate of proved oil and gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the reserves (including Syncrude) have been assessed by independent qualified reserves consultants.

Estimates of crude oil and gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. See Critical Accounting Estimates in Item 7 for a description of our oil and gas and mining reserves estimation process.

	Total		Yemen [1]	Canada			United States		United Kingdom		Other Countries [3]
Conventional oil and bitumen are in mmbbls and natural gas is in bcf	Oil	Gas	Oil	Oil	Gas	Bitumen [2]	Oil	Gas	Oil	Gas	Oil
Proved Developed and Undeveloped Reserves [4]											
December 31, 2005	**304**	**532**	**59**	**50**	**305**	**–**	**41**	**215**	**143**	**12**	**11**
Extensions and Discoveries	52	89	1	1	54	–	2	26	23	9	25
Purchases of Reserves in Place	–	1	–	–	1	–	–	–	–	–	–
Sales of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Revisions – Technical	2	(4)	(7)	(3)	(3)	–	(8)	(10)	19	9	1
Revisions – Economic	229	(12)	4	6	(10)	219	–	(2)	–	–	–
Production	(38)	(74)	(19)	(6)	(33)	–	(5)	(34)	(6)	(7)	(2)
December 31, 2006	**549**	**532**	**38**	**48**	**314**	**219**	**30**	**195**	**179**	**23**	**35**
Extensions and Discoveries	13	51	1	1	31	–	1	18	10	2	–
Purchases of Reserves in Place	3	42	–	–	1	–	2	41	1	–	–
Sales of Reserves in Place	–	(10)	–	–	–	–	–	(10)	–	–	–
Revisions – Technical	53	–	–	(1)	11	19	(4)	(19)	39	8	–
Revisions – Economic	–	(11)	(2)	4	(4)	(4)	(2)	(5)	4	(2)	–
Production	(57)	(72)	(14)	(5)	(35)	–	(6)	(31)	(30)	(6)	(2)
December 31, 2007	**561**	**532**	**23**	**47**	**318**	**234**	**21**	**189**	**203**	**25**	**33**
Extensions and Discoveries	26	39	1	1	34	19	–	5	5	–	–
Purchases of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Sales of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Revisions – Technical	20	40	6	(3)	54	–	2	(14)	17	–	(2)
Revisions – Economic	(3)	(21)	2	(19)	(16)	31	(3)	(5)	(16)	–	2
Production	(60)	(71)	(12)	(4)	(40)	(2)	(3)	(24)	(37)	(7)	(2)
December 31, 2008	**544**	**519**	**20**	**22**	**350**	**282**	**17**	**151**	**172**	**18**	**31**
Proved Developed Reserves [5]											
December 31, 2006	286	460	33	44	287	40	28	161	131	12	10
December 31, 2007	281	423	22	44	293	40	17	114	151	16	7
December 31, 2008	**244**	**464**	**19**	**22**	**329**	**52**	**12**	**124**	**133**	**11**	**6**

1 Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.

2 Represents bitumen reserves from the insitu recovery of Canadian oil sands, rather than upgraded synthetic crude oil reserves to be sold.

3 Represents reserves in Nigeria and Colombia.

4 Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.

5 Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

Our net proved reserves and changes in those reserves for our Syncrude operations are disclosed below. Additional disclosures required by SEC Industry Guide 7 are on pages 20 through 22. The net proved reserves represent management's best estimate of proved synthetic reserves after royalties.

Estimates of Syncrude's synthetic crude oil reserves are based on detailed geological and engineering assessments of the bitumen volume in-place, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling density of less than 500 metres. In accordance with the approved mining plan, there are an estimated 2 billion tons of economically extractable oil sands in the Mildred Lake North Mine, with an average bitumen grade of 10.3 weight percent. The Aurora North Mine contains an estimated 4.6 million tons of economically extractable oil sands at an average bitumen grade of 11.1 weight percent. Aurora South Lease 31 contains measured economically extractable oil sands of 3.8 billion tons at an average bitumen grade of 10.8 weight percent.

	Synthetic Crude Oil		
(millions of barrels)	**Mildred Lake**[1]	**Aurora**[2]	**Total**
December 31, 2005	**47**	**217**	**264**
Extensions and Discoveries	–	11	11
Revision – Economic	1	4	5
Production	(3)	(3)	(6)
December 31, 2006	**45**	**229**	**274**
Extensions and Discoveries	–	7	7
Revision – Economic	–	(7)	(7)
Production	(3)	(4)	(7)
December 31, 2007	**42**	**225**	**267**
Extensions and Discoveries	–	7	7
Revision – Economic	11	17	28
Production	(4)	(3)	(7)
December 31, 2008	**49**	**246**	**295**

1 Leases 17 and 22.
2 Leases 10, 12, 31 and 34.

B. Capitalized Costs (excluding Syncrude operations)

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
December 31, 2008				
Yemen	2,808	–	(2,610)	198
Canada	5,087	1,067	(2,179)	3,975
United States	4,152	246	(2,702)	1,696
United Kingdom	5,954	578	(2,159)	4,373
Other Countries	509	45	(113)	441
Total Capitalized Costs	**18,510**	**1,936**	**(9,763)**	**10,683**
December 31, 2007				
Yemen	2,178	–	(1,950)	228
Canada	4,364	734	(1,990)	3,108
United States	2,931	138	(1,765)	1,304
United Kingdom	4,318	405	(908)	3,815
Other Countries	105	158	(77)	186
Total Capitalized Costs	**13,896**	**1,435**	**(6,690)**	**8,641**
December 31, 2006				
Yemen	2,404	–	(2,128)	276
Canada	3,787	227	(1,467)	2,547
United States	2,768	121	(1,445)	1,444
United Kingdom	4,325	385	(432)	4,278
Other Countries	99	150	(78)	171
Total Capitalized Costs	**13,383**	**883**	**(5,550)**	**8,716**

C. Costs Incurred (excluding Syncrude operations)

		Oil and Gas				
(Cdn$ millions)	Total Oil and Gas	Yemen	Canada	United States	United Kingdom	Other
Year Ended December 31, 2008						
Property Acquisition Costs						
Proved	22	–	22	–	–	–
Unproved	69	–	6	63	–	–
Exploration Costs	650	9	222	132	157	130
Development Costs	1,795	92	717	251	545	190
Asset Retirement Costs	188	–	25	153	10	–
Total Costs Incurred	**2,724**	**101**	**992**	**599**	**712**	**320**
Year Ended December 31, 2007						
Property Acquisition Costs						
Proved	151	–	1	104	46	–
Unproved	59	–	34	24	1	–
Exploration Costs	637	15	93	311	128	90
Development Costs	1,817	124	675	414	551	53
Asset Retirement Costs	169	6	48	30	85	–
Total Costs Incurred	**2,833**	**145**	**851**	**883**	**811**	**143**
Year Ended December 31, 2006						
Property Acquisition Costs						
Proved	13	–	12	–	1	–
Unproved	125	–	105	19	1	–
Exploration Costs	514	37	74	242	71	90
Development Costs	2,051	145	884	399	595	28
Asset Retirement Costs	69	4	5	4	56	–
Total Costs Incurred	**2,772**	**186**	**1,080**	**664**	**724**	**118**

D. Results of Operations for Producing Activities (excluding Syncrude operations)

(Cdn$ millions)	Total Oil and Gas	Oil and Gas: Yemen	Canada	United States	United Kingdom	Other Countries
Year Ended December 31, 2008						
Net Sales	6,186	1,093	656	665	3,580	192
Production Costs	715	176	182	94	253	10
Exploration Expense	402	5	79	109	86	123
Depreciation, Depletion, Amortization and Impairment	1,859	160	208	475	999	17
Other Expenses (Income)	75	(10)	29	37	6	13
	3,135	762	158	(50)	2,236	29
Income Tax Provision (Recovery)	1,412	264	45	(19)	1,126	(4)
Results of Operations	**1,723**	**498**	**113**	**(31)**	**1,110**	**33**
Year Ended December 31, 2007						
Net Sales	4,576	1,086	441	616	2,285	148
Production Costs	668	171	175	102	212	8
Exploration Expense	326	5	27	134	69	91
Depreciation, Depletion, Amortization and Impairment	1,627	213	166	641	599	8
Other Expenses (Income)	100	(8)	66	38	(36)	40
	1,855	705	7	(299)	1,441	1
Income Tax Provision (Recovery)	859	248	2	(103)	712	–
Results of Operations	**996**	**457**	**5**	**(196)**	**729**	**1**
Year Ended December 31, 2006						
Net Sales	3,032	1,328	459	629	477	139
Production Costs	491	151	146	106	80	8
Exploration Expense	362	4	26	214	46	72
Depreciation, Depletion, Amortization and Impairment	1,011	327	162	296	216	10
Other Expenses (Income)	71	15	106	(23)	(71)	44
	1,097	831	19	36	206	5
Income Tax Provision	687	289	6	13	378	1
Results of Operations	**410**	**542**	**13**	**23**	**(172)**	**4**

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein (excluding Syncrude operations)

The following disclosure is based on estimates of net proved reserves (excluding Syncrude) and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved oil and gas reserves (excluding Syncrude operations). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	United Kingdom	Other Countries
December 31, 2008						
Future Cash Inflows	25,305	904	12,260	1,809	8,753	1,579
Future Production Costs	10,847	424	6,619	765	2,616	423
Future Development Costs	3,008	51	1,488	33	564	872
Future Dismantlement and Site Restoration Costs, Net	1,421	20	332	446	558	65
Future Income Tax	2,653	141	–	–	2,467	45
Future Net Cash Flows	7,376	268	3,821	565	2,548	174
10% Discount Factor	2,953	24	1,988	84	505	352
Standardized Measure	**4,423**	**244**	**1,833**	**481**	**2,043**	**(178)**
December 31, 2007						
Future Cash Inflows	43,888	1,952	17,365	3,207	17,977	3,387
Future Production Costs	11,988	468	7,229	539	3,347	405
Future Development Costs	3,229	22	957	328	778	1,144
Future Dismantlement and Site Restoration Costs, Net	1,143	16	273	197	595	62
Future Income Tax	8,793	452	1,135	437	6,589	180
Future Net Cash Flows	18,735	994	7,771	1,706	6,668	1,596
10% Discount Factor	7,606	111	4,236	441	1,561	1,257
Standardized Measure	**11,129**	**883**	**3,535**	**1,265**	**5,107**	**339**
December 31, 2006						
Future Cash Inflows	32,247	2,330	12,678	3,151	11,437	2,651
Future Production Costs	9,523	606	5,615	791	2,236	275
Future Development Costs	3,190	115	1,156	332	891	696
Future Dismantlement and Site Restoration Costs, Net	1,006	11	289	197	471	38
Future Income Tax	5,204	489	753	450	3,308	204
Future Net Cash Flows	13,324	1,109	4,865	1,381	4,531	1,438
10% Discount Factor	4,951	106	2,484	321	970	1,070
Standardized Measure	**8,373**	**1,003**	**2,381**	**1,060**	**3,561**	**368**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	2008	2007	2006
Beginning of Year	11,129	8,373	8,042
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(4,387)	(3,010)	(2,291)
Net Changes in Prices and Production Costs Related to Future Production	(9,756)	3,385	(1,065)
Extensions, Discoveries and Improved Recovery, Less Related Costs	376	758	695
Changes in Estimated Future Development and Dismantlement Costs	(676)	(443)	(692)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	1,343	1,102	1,048
Revisions of Previous Quantity Estimates	615	2,189	1,936
Accretion of Discount	1,730	1,191	1,117
Purchases of Reserves in Place	–	272	2
Sales of Reserves in Place	–	(49)	(2)
Net Change in Income Taxes	4,049	(2,639)	(417)
End of Year	**4,423**	**11,129**	**8,373**

ITEM 9.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There were no disagreements with accountants on accounting and financial disclosure.

ITEM 9A.

Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), or caused such disclosure controls and procedures to be designed under their supervision, to ensure that material information relating to the Company is made known to them, particularly during the period in which this report is prepared. They have evaluated the effectiveness of such disclosure controls and procedures as of the end of the period covered by this report (Evaluation Date). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective (i) to ensure that information required to be disclosed by us in reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms; and (ii) to ensure that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is accumulated and communicated to our management, including the Company's Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

The Company's management, including its Chief Executive Officer and Chief Financial Officer, does not expect that the Company's disclosure controls and procedures or internal controls will prevent all possible error and fraud. The Company's disclosure controls and procedures are, however, designed to provide reasonable assurance of achieving their objectives, and the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's financial controls and procedures are effective at that reasonable assurance level.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2008. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report which is on page 132 of this Form 10-K and has issued an attestation report on our internal control over financial reporting.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems of internal controls over financial reporting. There have not been any changes in the Company's internal control over financial reporting during the last quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. As well, no material weaknesses requiring corrective action were identified in the conduct of our evaluation of internal control over financial reporting. As a result, no such corrective actions were taken.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the internal control over financial reporting of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the Company's Board of Directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the Consolidated Financial Statements of the Company as of and for the year ended December 31, 2008, and our report dated February 11, 2009, expressed an unqualified opinion on those financial statements and includes a separate report titled Comments by Independent Registered Chartered Accountants on Canada—United States of America Reporting Difference referring to changes in accounting principles that have a material effect on the comparability of the Company's Consolidated Financial Statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 11, 2009

CORPORATE GOVERNANCE

As a leader in corporate governance,
we are committed to transparent disclosure
for all stakeholders.

PARTS III AND IV

ITEMS 10 AND 11.
Directors, Executive Officers and Corporate Governance, and Executive Compensation

ITEM 12.

ITEM 13.

ITEM 14.

ITEM 15.

PART III

ITEMS 10 AND 11.

Directors, Executive Officers and Corporate Governance, and Executive Compensation

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. In December 2008, the board expanded its size from 12 to 14 directors pursuant to the provisions granted in our articles and approved the appointment of Mr. Berry (effective December 8, 2008) and of Mr. Bertram (effective January 1, 2009). Mr. Fischer retired on December 31, 2008 and Mr. Romanow was appointed to the board effective January 1, 2009 upon his appointment as President and Chief Executive Officer (CEO). They are management nominees for election to the board at the 2009 annual general meeting of shareowners (AGM). All other directors were elected at the last AGM. On February 11, 2009, the board determined to set the size at 12 directors effective April 28, 2009 when Mr. Hentschel and Mr. Thomson retire.

Our By-Laws provide that directors will be elected at the AGM each year and will hold office until their successors are elected.

Name (Age)	**Principal Occupation**	**Other Directorships**	**Nexen Director Since**
William B. Berry (56)	Retired oil executive. Formerly: Executive Vice President of ConocoPhillips.	Willbros Group, Inc.	2008
Robert G. Bertram (64)	Retired pension investment executive. Formerly: Executive Vice President of Ontario Teachers Pension Plan Board.	The Cadillac Fairview Corporation Maple Leaf Sports and Entertainment Ltd.	2009
Dennis G. Flanagan (69)	Retired oil executive.	Canexus Income Fund (Chair) NAL Oil & Gas Trust	2000
David A. Hentschel [3] (75)	Retired oil executive. Formerly: Oil and gas consultant.	Cimarex Energy Co.	1985
S. Barry Jackson [1] (56)	Retired oil executive. Formerly: Chair of Resolute Energy Inc. and Chair of Deer Creek Energy Limited.	TransCanada Corporation (Chair) TransCanada PipeLines Limited (Chair)	2001
Kevin J. Jenkins [1,2] (52)	Managing Director of TriWest Capital Partners. Formerly: President and CEO of The Westaim Corporation.	–	1996
A. Anne McLellan, P.C. [1] (58)	Counsel with Bennett Jones LLP, Barristers and Solicitors, and Distinguished Scholar in Residence at the University of Alberta in the Institute for United States Policy Studies. Formerly: Member of Parliament for Edmonton Centre, Deputy Prime Minister, Minister of Public Safety and Emergency Preparedness and Minister of Health.	Agrium Inc. Cameco Corporation	2006
Eric P. Newell, O.C. [1] (64)	Retired Chair and CEO of Syncrude Canada Ltd.	–	2004
Thomas C. O'Neill [1,2] (63)	Retired Chair of PwC Consulting. Formerly: CEO of PwC Consulting. Prior to that, COO of PricewaterhouseCoopers LLP, Global.	Adecco S.A. BCE Inc. Loblaw Companies Limited The Bank of Nova Scotia	2002
Marvin F. Romanow (53)	President and CEO of Nexen. Formerly: Executive Vice President and CFO of Nexen.	Canexus Income Fund	2009
Francis M. Saville, Q.C. [1] (70)	Chair of Nexen. Counsel with Fraser Milner Casgrain LLP, Barristers and Solicitors. Formerly: Senior Partner and Vice Chair of Fraser Milner Casgrain LLP, Barristers and Solicitors.	–	1994
Richard M. Thomson, O.C. [1,2] (75)	Retired banking executive.	The Thomson Corporation	1997
John M. Willson [1] (69)	Retired mining executive.	Finning International Inc.	1996
Victor J. Zaleschuk [4] (65)	Retired oil executive.	Agrium Inc. Cameco Corporation (Chair)	1997

1 *All members of the Audit and Conduct Review (Audit), Corporate Governance and Nominating (Governance), and Compensation and Human Resources (Compensation) Committees are independent. All members of the Audit Committee are independent under additional regulations for audit committee members.*

2 *Financial Experts on Nexen's Audit Committee.*

3 *Mr. Hentschel was Chair and CEO of Occidental Oil and Gas Corporation from 1997 to 1999 and President and CEO of Nexen from 1995 to 1997.*

4 *Mr. Zaleschuk was President and CEO of Nexen from 1997 to 2001.*

INDEPENDENCE AND BOARD COMMITTEES

The board affirmed director independence under our categorical standards for director independence (categorical standards), which are available at www.nexeninc.com. The categorical standards have been in place since 2003 and most recently amended on February 11, 2009. Our categorical standards meet or exceed the requirements in SEC rules and regulations, the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley), the NYSE rules, *National Policy 58-201—Corporate Governance Guidelines, Multilateral Instrument 52-110—Audit Committees,* and applicable provisions of *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities.*

Mr. Romanow is not independent as he is Nexen's President and CEO.

Mr. Flanagan is not independent as his son is Senior Vice President, Engineering of TriAxon Resources Ltd. (TriAxon). In 2006, TriAxon acquired a company that was party to contracts with a Nexen subsidiary. Under one of the contracts, Nexen paid approximately $4.5 million to TriAxon between July and December 2006 for products purchased at market price. Accordingly, Mr. Flanagan is not technically independent as of July 1, 2007. Mr. Flanagan was not aware that the company acquired by TriAxon held contracts with Nexen. The board has determined that Mr. Flanagan's independence has not been compromised by this transaction and, accordingly, the board continues to include him in their meetings without management.

Ms. McLellan has been counsel with Bennett Jones LLP (BJ), Barristers and Solicitors, Edmonton, Alberta since June 27, 2006. BJ provided legal services to us in each of the last five years. Ms. McLellan does not solicit or participate in those services, does not receive any fees we pay to BJ, nor is she a partner or an employee of the firm. She is independent under our categorical standards.

Mr. Saville has been counsel with Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta since February 1, 2004. Prior to that time, he was a senior partner of the firm. FMC provided legal services to us in each of the last five years. Mr. Saville does not solicit or participate in those services, does not receive any fees we pay to FMC, nor is he a partner or an employee of the firm. He is independent under our categorical standards.

We have not had an executive committee of the board since July 11, 2000.

	Committees (Number of Members)					
	Audit[1,2] (6)	**Compensation**[1] (7)	**Governance**[1] (7)	**Finance** (6)	**HSE&SR** (8)	**Reserves**[3] (7)
Management Director—Not Independent						
Marvin F. Romanow						
Outside Director—Not Independent						
Dennis G. Flanagan				√	√	√
Independent Outside Directors						
William B. Berry[4]						
Robert G. Bertram[4]						
David A. Hentschel				√	√	√
S. Barry Jackson	√	√			Chair	√
Kevin J. Jenkins[5]	√	Chair	√		√	
A. Anne McLellan, P.C.		√	√	√	√	
Eric P. Newell, O.C.	√		√		√	√
Thomas C. O'Neill[5,6]	Chair	√	√			√
Francis M. Saville, Q.C.		√	√	√	√	
Richard M. Thomson, O.C.[5]	√	√	Chair	√		
John M. Willson	√	√	√			Chair
Victor J. Zaleschuk				Chair	√	√

1 *All members are independent. All Audit Committee members are independent under additional regulatory requirements applicable to them.*

2 *Experience of the members of the Audit Committee that indicates an understanding of the accounting principles we use to prepare our financial statements is shown in their biographies on page 135.*

3 *A majority of the Reserves Committee members are independent.*

4 *Mr. Berry and Mr. Bertram will receive committee appointments on April 28, 2009, as determined by the board.*

5 *Audit committee financial expert under US regulatory requirements.*

6 *The board has determined that Mr. O'Neill's service on the audit committees of four other public companies and one not-for-profit organization does not impair his ability to serve as Chair of Nexen's Audit Committee. The board considered that Mr. O'Neill has over 30 years of experience as a chartered accountant and, since retiring as Chair of PwC Consulting in 2002, his only business commitments are to the boards and committees on which he serves.*

Audit Committee Financial Expert Experience

Name	Jenkins	O'Neill	Thomson
Experience	Kevin Jenkins, 52, is a Managing Director of TriWest Capital Partners, an independent private equity firm. He was President, CEO and a director of The Westaim Corporation from 1996 to 2003. From 1985 to 1996 he held senior executive positions with Canadian Airlines International Ltd. (Canadian). He was elected to serve on Canadian's Board of Directors in 1987, appointed President in 1991 and appointed President and CEO in 1994. Mr. Jenkins has a Bachelor's Degree in Law from the University of Alberta and a Master of Business Administration from Harvard Business School. He has worked in management positions with increasing level of responsibility including Assistant Treasurer, Vice President Finance, Executive Vice President and Chief Financial Officer, and President and CEO. Kevin is Vice Chair and a director of World Vision Canada.	Tom O'Neill, 63, is the retired Chair of PwC Consulting. He was formerly CEO of PwC Consulting, COO of PricewaterhouseCoopers LLP, Global, CEO of PricewaterhouseCoopers LLP, Canada and Chair and CEO of Price Waterhouse Canada. He worked in Brussels in 1975 to broaden his international experience and from 1975 to 1985 was client service partner for numerous multi nationals, specializing in dual Canadian and US listed companies. Mr. O'Neill has a Bachelor of Commerce Degree from Queen's University. He received his Chartered Accountant designation in 1970 and was made a Fellow (FCA) of the Institute of Chartered Accountants of Ontario in 1988. He also has an Honorary Doctorate of Law from Queen's University. Tom is a director of BCE Inc., Loblaw Companies Limited, The Bank of Nova Scotia and Adecco S.A. He is a member of the External Audit Committee of the International Monetary Fund. He is also Vice Chair of the Board of Governors of Queen's University.	Dick Thomson, 75, is a retired banking executive. He was with the Toronto-Dominion Bank, one of Canada's largest banks, since 1957, as President from 1972 to 1978 and as Chair from 1978 until his retirement in 1998. Mr. Thomson holds a Master of Business Administration from Harvard Business School and a Bachelor of Arts and Science in Engineering from the University of Toronto. He is an Officer of the Order of Canada. Dick is a director of the board of the Multiple Sclerosis Scientific Research Foundation.

Director and Officer Liability Insurance

We maintain a director and officer liability insurance policy. The policy covers costs to defend and settle claims against Nexen's directors and officers to an annual limit of US$150 million. It includes a US$12.5 million deductible for an indemnifiable occurrence and no deductible for a non-indemnifiable occurrence. The cost of coverage for 2008 was approximately US$951,000. Directors and officers do not pay premiums and no indemnity claims were made or paid in 2008.

Director and Officer Fiduciary Insurance

Nexen maintains a fiduciary liability insurance policy. It covers costs to defend and settle claims against Nexen, our directors, officers and employees for breach of fiduciary duty related to company-sponsored plans, such as pension and savings plans. The policy has an annual limit of US$25 million with a US$2.5 million deductible for an indemnifiable occurrence and no deductible for a non-indemnifiable occurrence. The cost of coverage for 2008 was approximately US$27,600. Directors and officers do not pay premiums and no claims were made or paid in 2008.

Loans to Directors

As set out in the corporate governance policy, we do not make loans to our directors. There are no loans outstanding from Nexen to our directors.

DIRECTOR COMPENSATION

Nexen provides all directors with a comprehensive compensation package of annual cash retainers, meeting fees and equity-based incentives in the form of deferred share units (DSUs). The package provides competitive remuneration for the increasing responsibilities, time commitments and accountability of board members. Management, the Compensation Committee and the board regularly review the compensation for competitiveness against a peer group of oil and gas companies. We target and currently provide total compensation between the 50th and 75th percentile to attract and retain qualified talent to our board.

Directors may choose select benefits coverage at Nexen's expense, including basic life insurance, extended health care, dental, business travel accident insurance, and reimbursement of provincial health care premiums (in certain jurisdictions). Directors do not receive compensation from a non-equity incentive plan. Mr. Zaleschuk, a former CEO of Nexen, is a retiree in Nexen's pension plan. His pension benefit is for previous employee service.

See page 137 for more information on DSUs.

Director Compensation Table

Name	Total Fees Earned[1]	DSU Awards[2]	All Other Compensation[3]	Total Compensation
Berry	6,217	96,800	–	103,017
Flanagan	110,000	96,800	96,054[4]	302,854
Hentschel	114,500	96,800	4,458	215,758
Jackson	135,500	96,800	5,887	238,187
Jenkins	137,300	96,800	6,579	240,679
McLellan	130,200	96,800	2,719	229,719
Newell	126,600	96,800	7,383	230,783
O'Neill	154,100	96,800	6,105	257,005
Saville	254,500	154,880	5,731	415,111
Thomson	143,300	96,800	9,552	249,652
Willson	144,500	96,800	6,459	247,759
Zaleschuk	115,300	96,800	4,876	216,976
Total	**1,572,017**	**1,219,680**	**155,803**	**2,947,500**

1 *Includes all retainers and meetings fees, including those paid in DSUs.*
2 *The value of DSUs granted on December 8, 2008, based on the closing market price of Nexen common shares on the TSX on December 5, 2008 of $19.36/share. See page 137 for details.*
3 *The total value of perquisites provided to each director is less than both $50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2008 valued at the closing market price of Nexen common shares on the TSX on the payment dates, travel allowance paid by Nexen, and Canexus fees as set out in note 4.*
4 *Mr. Flanagan is the Board Chair of Canexus and was paid fees of $59,000, received deferred trust units of Canexus valued at $21,840 and distributions on his trust units of $10,630 in 2008. The total is included in this column.*

Director Retainers and Fees

Annual board and committee retainers are paid quarterly and pro-rated for partial service. The same fees are paid for attending meetings in person or by conference call. A travel allowance of $1,500 was introduced in 2007. It is paid when a non-executive director travels outside his or her home province or state, or travels more than three hours, round trip, to attend a Nexen meeting or site visit. Nexen also reimburses directors for out-of-pocket travel expenses.

	2008	2009
Board Chair Retainer	250,000[1]	250,000[1]
Board Member Retainer	35,000	35,000
Audit Committee Chair Retainer	19,700	19,700
Other Committee Chair Retainer	5,300	5,300
Committee Member Retainer	9,100	9,100
Board and Committee Meeting Fees (per meeting attended)	1,800	1,800

1 *As of January 1, 2008, the Board Chair is paid only this retainer and the travel allowance. He does not receive any other retainers or meetings fees.*

2008 Retainers and Fees

Name	Annual Board Retainer	Annual Committee Retainers	Annual Committee Chair Retainer	Board Meeting Fees	Committee Meeting Fees	Travel Allowance	Total Fees Earned	Total Fees Credited in DSUs[1]	Percentage of Fees Credited in DSUs[1]	Total Fees Earned in Cash
Berry	2,917	–	–	1,800	–	1,500	6,217	–	–	6,217
Flanagan	35,000	27,300	–	18,000	25,200	4,500	110,000	–	–	110,000
Hentschel	35,000	27,300	–	18,000	25,200	9,000	114,500	–	–	114,500
Jackson	35,000	36,400	5,300	18,000	37,800	3,000	135,500	132,500	98%	3,000
Jenkins	35,000	36,400	5,300	18,000	39,600	3,000	137,300	–	–	137,300
McLellan	35,000	36,400	–	18,000	37,800	3,000	130,200	127,200	98%	3,000
Newell	35,000	36,400	–	18,000	34,200	3,000	126,600	123,600	98%	3,000
O'Neill	35,000	36,400	19,700[2]	18,000	36,000	9,000	154,100	–	–	154,100
Saville	250,000	–	–	–	–	4,500	254,500	–	–	254,500
Thomson	35,000	36,400	5,300	18,000	39,600	9,000	143,300	134,300	94%	9,000
Willson	35,000	36,400	5,300	18,000	37,800	12,000	144,500	–	–	144,500
Zaleschuk	35,000	27,300	5,300	18,000	25,200	4,500	115,300	–	–	115,300
Total	**602,917**	**336,700**	**46,200**	**181,800**	**338,400**	**66,000**	**1,572,017**	**517,600**		**1,054,417**

1 *Details of DSU holdings are set out in the table on page 137.*
2 *Mr. O'Neill is the Audit Committee Chair.*

Share Ownership Guideline

One way our directors demonstrate their commitment to Nexen's success is through share ownership. On February 14, 2008, the board approved guidelines for directors to own or control at least 16,800 shares or DSUs. This amount represents at least three times both the base annual board retainer of $35,000 and the value of the base annual DSU grant. Directors must accumulate DSUs as follows:

- 5,600 by year 1
- 11,200 by year 2
- 16,800 by year 3

New directors, if eligible, are required to take their annual retainer in DSUs until the current threshold is met. Eligibility is based on country of residence and Mr. Berry, as a US resident, is not eligible to take his annual retainer in DSUs. If there is a change in share value or number of DSUs granted that affects a director's ability to meet the requirement, he or she will have nine months to meet the threshold again.

All directors surpass these guidelines.

Deferred Share Units

Nexen has two DSU plans. Under the first plan, eligible directors may elect annually to receive all or part of their fees in DSUs, rather than cash. The second plan was implemented in 2003 and replaced stock options as the long-term incentive to align director and shareowner interests.

DSUs provide directors with a stake in Nexen while they serve on the board. DSUs do not have voting rights as there are no shares underlying the plans. A DSU is a bookkeeping entry that tracks the value of one Nexen common share. When cash dividends are paid on our common shares, eligible directors are credited DSUs equal to the dividend. DSUs accumulate over a director's term of service and are only paid when the director leaves the board. Then, at Nexen's option, payments may be made in cash or in Nexen common shares purchased on the open market.

Name	DSUs Held as of December 31, 2008 [1]
Berry	5,000
Flanagan	35,660
Hentschel	35,656
Jackson	48,145
Jenkins	48,789
McLellan	26,943
Newell	57,824
O'Neill	45,618
Saville	46,117
Thomson	72,672
Willson	48,200
Zaleschuk	37,430

1 Number of DSUs has been adjusted to account for Nexen's share splits that occurred in May 2005 and May 2007.

Mr. Bertram was appointed to the board on January 1, 2009 and received a grant of 5,000 DSUs. The effective date of the grant was January 2, 2009 with a base price of $21.45 per DSU, which was the closing market price of Nexen common shares on the TSX on December 31, 2008. The value of the DSU grant was $107,250. Mr. Berry was appointed to the board on December 8, 2008 and received DSUs as set out in the table above.

TOPs Exercised or Exchanged and Awards Vested During 2008

In 2008, no tandem options (TOPs) were exercised or exchanged by the board, which demonstrates that directors are holding TOPs for the long-term—consistent with our long-term strategy—and not for short-term purposes. Under the DSU plan, there are no vesting provisions and no value realized on vesting.

COMPENSATION COMMITTEE REPORT

The Compensation Committee assists the board in overseeing key compensation and human resource policies, CEO and executive compensation, and executive management succession and development. The Committee reports to the board, as set out in its mandate, and the board or independent directors give final approval on compensation matters.

All Committee members are independent and knowledgeable in our compensation programs and their long-term implications. Five members are skilled or expert in compensation—expertise most relevant to the Committee's mandate.

Changes to Committee Membership in 2008

The Committee membership did not change in 2008.

Committee Work Plan

The Committee held seven meetings and sessions without management present in 2008. While each meeting agenda is subject to change as business needs arise, the timing of the Committee's main activities are provided in this table.

Agenda Items	
Approved compensation disclosure and Committee report in the proxy circular Recommended the prior year's incentive bonus plan pay-out factor Recommended the current year's bonus performance target and compensation program Reviewed CEO's prior year accountabilities and results, and provided a bonus recommendation Reviewed CEO's current year accountabilities recommendations and provided a salary recommendation	February 2008
Reviewed competitive analysis of long-term incentive program	July 2008
Reviewed market activity update Reviewed workforce plan	October 2008
Recommended long-term incentive grants Reviewed market activity update Reviewed succession and development plan	December 2008
In camera meetings	At each meeting

Key Activities in 2008

The key activities reviewed and recommended during the year are outlined below:

- compensation programs and budgets for base salary, annual cash and long-term incentives (Tandem Option Plan (TOPs) and Stock Appreciation Rights Plan (StARs));
- salaries, bonuses and grants of TOPs to the executives;
- retention programs for key business initiatives;
- CEO performance on short-term and long-term corporate goals and objectives;
- CEO compensation, which was approved by the independent directors of the board;
- CEO's annual objectives and our executive management succession and development plans;
- CEO and CFO appointments and compensation;
- directors' annual deferred share unit grants;
- impact of current compensation on change of control agreements;
- employee benefit plans;
- competitive updates on compensation programs, market forecasts and workforce planning;
- executive compensation disclosure and Committee report for the proxy circular; and
- Canadian Securities Administrators' new rules on executive compensation disclosure for the proxy.

Outside Consultant

The Committee engaged Mercer (Canada) Limited (Mercer) to confidentially report and analyze market data on the CEO's compensation, in light of our operations and compensation programs. Mercer also provided a compensation report on a select group of our executives. The reports included competitive information from a list of peer companies recommended by Mercer. The Committee's decisions are its responsibility and may reflect factors other than the information and recommendations provided by Mercer and management.

Mercer did not provide compensation consulting services to management in 2008. We participated in compensation surveys in Canada and internationally, and purchased select published results. Management must obtain Committee approval before retaining Mercer for consulting services.

Fees Billed by Outside Consultant (Mercer)

Type of Fee	Billed in 2007	Billed in 2008	Percentage of Total Fees Billed in 2008
Committee Work—assessment of CEO and executive compensation	49,610	58,900	100%
Management Work—consulting services	–	–	–
Total Annual Fees	**49,610**	**58,900**	**100%**

External Recognition and Verification

Nexen was recognized in 2008 by Benefits Canada magazine for having one of Canada's 30 Best Pension and Benefits Plans.

Committee Approval

The Committee has reviewed and discussed with management the compensation disclosure in this document, including the information in the Board of Directors section (pages 135 to 136), the Compensation Discussion and Analysis section (pages 139 to 147) and the Executive Compensation section (pages 147 to 157). It has recommended to the board that the disclosure be included in the circular and, as appropriate, the Form 10-K.

Submitted on behalf of the Compensation Committee:

Kevin Jenkins, Chair
Francis Saville
Barry Jackson
Dick Thomson
Anne McLellan
John Willson
Tom O'Neill

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation Committee are set out on page 134. Mr. Saville had a relationship requiring disclosure, the details of which are set out under "Certain Relationships and Related Transactions, and Director Independence" on page 161. There are no Compensation Committee interlocks during 2008.

COMPENSATION DISCUSSION AND ANALYSIS

Our compensation disclosure complies with the requirements of the Canadian Securities Administrators. As a foreign private issuer in the US, we are not required to disclose compensation according to the SEC rules, but we attempt to comply with the spirit of those rules where possible, without compromising required Canadian disclosure.

Compensation Philosophy

Our policies and practices for executive compensation are linked to strategic business objectives, including increasing shareowner returns. Our philosophy is to compensate executives:

- based on performance;
- at a level competitive with our peers; and
- in a manner designed to attract and retain talented leadership focused on managing Nexen's operations, finances and assets.

All of our compensation programs are designed to meet pay-for-performance and competitiveness objectives. Actual rewards are directly linked to the results of Nexen and our divisions. The objective and subjective performance measures are aligned with shareowner interests, and financial and non-financial goals. Measures set each year represent improvements and growth to our operations relative to prior years.

Our programs are responsive to market changes. We aim for simplicity in our compensation programs to help employees understand the value of the various components and how they can contribute to business results. Executive programs are generally consistent with employee programs in the same location. Where certain programs, such as perquisites, are only provided to executives or senior management, they reflect competitive practice and particular business needs and objectives.

Benchmark Review

We use third-party compensation surveys to compare our pay levels and practices, including base pay, annual cash incentives and long-term incentives, to our peers. We look at Canadian-based oil and gas and integrated pipeline companies with whom we compete for talent. Given similar positions across the industry, the surveys effectively represent competitive pay levels. It should be noted, however, we do not know the extent to which our peers participate in the surveys and benchmark each position. The peer groups are modified over time to reflect: (i) geographical location, (ii) a particular business line, (iii) a more comparable position, or (iv) industry mergers and acquisitions.

Our peer groups are reviewed annually by third-party consultants and the Compensation Committee for continued relevance. In 2008, our executive peer group consisted of the following 16 major oil and gas and integrated pipeline companies:

BP Canada Energy Company	Husky Energy Inc.
Canadian Natural Resources Limited	Imperial Oil Limited
Chevron Canada Resources	Petro-Canada
ConocoPhillips Canada	Shell Canada Limited
Devon Canada Corporation	Suncor Energy Inc.
Enbridge Inc.	Syncrude Canada Limited
EnCana Corporation	Talisman Energy Inc.
ExxonMobil Canada	TransCanada Corporation

For the CEO, the peer group is a subset of the 16 peer companies. This peer group focuses on the major Canadian-based and independent oil and gas companies that have more comparable CEO positions.

The Compensation Committee reviews all programs to ensure we continue to attract and retain the high-performing employees needed to achieve our business objectives, while demonstrating long-term fiscal responsibility to shareowners.

COMPENSATION OBJECTIVES

Our compensation programs include three elements: base salary, annual cash incentive and long-term incentive. At least once a year, we assess the competitiveness of these individual components and the overall compensation levels. Our goal is to provide total compensation for fully qualified and performing employees between the 50th and 75th percentile as compared to our peers. Top-performing employees will approach the 75th percentile as they continue to accumulate knowledge and experience, which is accompanied by sustained high performance.

Key Elements of Compensation

Element	Component	Form	Performance Period
Base salary	Fixed	Cash	1 year
Annual cash incentive	Variable	Cash	1 year
Long-term incentive	Variable	TOPs and StARs	Greater than 1 year

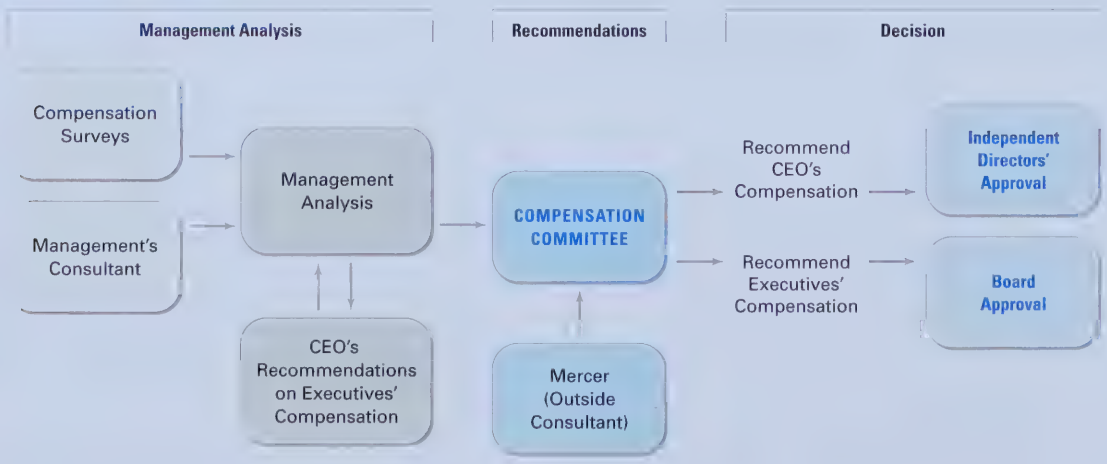
Pay Mix

Since our compensation programs are designed to meet both performance and competitiveness objectives, actual pay will vary from year-to-year within our pay mix. In general, the programs are designed to provide most executive compensation in the form of at-risk pay to ensure alignment with shareowners. Base salary provides a competitive foundation considering both internal comparability and external market data. Annual cash incentives reward the delivery of results against objective and subjective measures within a one-year period. Long-term incentives reward Nexen's sustained performance as seen in share price appreciation. The actual mix between the compensation elements varies, depending on the executives' ability to influence short and long-term business results, their level and competitive local market practices.

		At-Risk Compensation [1]	
Position	Base Salary	Annual Cash Incentive	Long-Term Incentive
CEO	15%	20%	65%
CFO	25%	20%	55%
Executive VPs	25%	20%	55%
Senior VPs	30%	20%	50%

1 Represents the percentage of total compensation, excluding benefits, pension and perquisites averaged over a three-year period.

Compensation Approval Process



In determining our executives' base salary, annual cash and long-term incentives, the Compensation Committee considers a comprehensive analysis, including a tally sheet prepared by management with input from an executive compensation consultant. The analysis includes market data for similar positions within the peer group and CEO recommendations for his direct reports, including all of the other named executive officers (executives), and information on prior year annual cash and long-term incentives. The basic design of our short and long-term incentive programs mitigates the need to present various performance scenarios to show impact on payout levels. However, before approving management's compensation recommendations, the Committee discusses a variety of scenarios, including analysis of various annual cash incentive payout factors and the impact of share price variation on our long-term incentive program. For more complex programs, such as pension, management provides the Committee with a sensitivity analysis that considers the pension cost implications for each 1% of incremental pensionable earnings.

The Committee reviews the three compensation elements both individually, and in total, to ensure they align with the program objectives. In addition, the Committee retains the services of its own executive compensation consultant, Mercer, to provide external market data and commentary on the relative positioning of executives, particularly the CEO. The Committee then makes recommendations on all executive payments and grants to the board or independent directors for approval. Typically, this process begins in the fall and concludes with total compensation being approved the following February.

BASE SALARIES

To determine base salaries, a framework of job levels based on internal comparability and external market data is used. We also consider the individual's current and sustained performance, skills and potential.

ANNUAL CASH INCENTIVES

The program provides an opportunity for competitive bonus compensation that reflects Nexen's overall and division performance and that of the individual. Variable compensation links Nexen's business results and the executives' performance, consistent with our pay-for-performance philosophy. The increase in the executives' annual cash incentives in 2008 reflects the board's assessment of our relative level of success on certain business objectives.

2008 Annual Incentive Measures

After reviewing Nexen's objective and subjective performance measures, the board, at the recommendation of the Compensation Committee, approves the payout factor. The payout factor determines the cash pool available for annual cash incentives and may range from 0 to 200%. The factors used were 120% in 2006, 88% in 2007 and 120% in 2008.

2008 Objective Performance Measures (50%)

These key financial measures are consistent with our annual operating plan.

Measure	Target	Results	Results versus Target
Cash flow (25%)	$2,912 million	$4,229 million	145%
Net income (25%)	$1,330 million	$1,715 million	129%

2008 Subjective Performance Measures (50%)

The Compensation Committee subjectively considers a combination of quantitative and qualitative measures. The individual measures are not assigned a fixed weighting. This allows the Committee to exercise its discretion and increase or decrease the payout factor when assessing our overall performance. Its discretion ensures the award is not unduly impacted by an unusual result in any one area. The business measures that the Committee considers are commonly used in our industry. They include, among other measures, stock performance, annual stock performance against peers, production volumes, safety and environmental incidents, and reserve-related metrics. The Committee also assesses costs, including finding and development, operating and administrative. The business measures are assessed against objectives in light of our external environment and current business circumstances, including key projects and initiatives critical to Nexen's success. Both absolute performance and performance relative to peers are reviewed. The Committee also considers management's assessment of Nexen's performance and progress against the strategic plan.

If Nexen does not achieve the minimum pre-determined performance level of any component of the objective measures, no allocation will be made for that component in the overall assessment of the payout factor. The Committee's assessment of the subjective measures could also result in a decrease of the payout factor. Alternatively, exceptional performance in our objective and subjective measures may be rewarded with a 200% payout factor, which is the maximum allowed under the annual incentive plan. Exceptional performance means that we exceeded

our objective measure targets by at least 25%. For 2008, the Committee considered that Nexen's overall performance exceeded target. Record financial results and strong relative share price performance were balanced against disappointing results from the Marketing division and impairment charges.

Annual Cash Incentive Payout

The cash pool available for annual incentives is then allocated to employees and executives based on individual incentive target levels and performance. The targets for individual awards increase as job responsibilities grow so that the ratio of at-risk versus fixed compensation is greater for higher levels of responsibility. Individual performance is assessed by the direct supervisor and reflects performance against pre-determined objectives. The actual incentive award received by the individual may be more or less than target level. Typically, annual incentive awards range from 0 to 200% of the target for that position.

2008 Annual Incentive Targets [1]

Position	Minimum	Target	Maximum
CEO [2]	0%	80%	160%
CFO [3]	0%	60%	120%
Executive VPs	0%	60%	120%
Senior VPs	0%	45%	90%

1 *Reflects percentage of base salary on December 31, 2008.*
2 *The target decreased to 75% and the maximum to 150% effective January 1, 2009 with the appointment of the new CEO.*
3 *The target decreased to 50% and the maximum to 100% effective January 1, 2009 with the appointment of the new CFO.*

Reimbursement

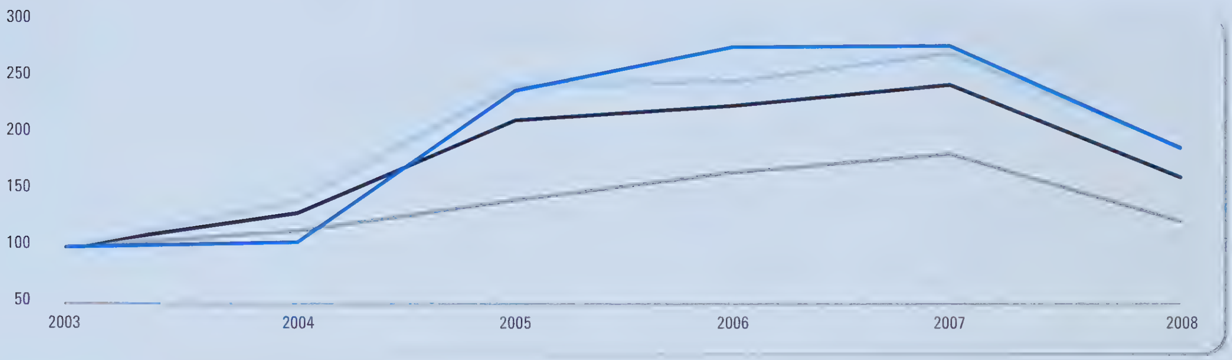
If, as a result of misconduct, Nexen's performance results were restated in a way that decreased the incentive awards, the CEO and CFO would reimburse Nexen proportionately as required by law.

While Nexen is aligned and committed to the US requirements for clawbacks, we are consulting with industry leaders and shareholder advisory groups to better understand the development of clawback policy models in Canada. Identified barriers to implementation include employment law, enforcement and tax issues. Nexen is working to implement a more formal solution that effectively addresses alignment of shareowner and executive interests by ensuring that compensation is not increased as a result of willful misconduct.

SHARE PERFORMANCE GRAPH

While share performance is not the only indicator of pay levels, a more direct alignment can be seen with our annual incentive program and the value realized by employees participating in our long-term incentive programs. There has not been a direct correlation between base salary levels and Nexen share performance. The sharp increase to our share price from 2004 to 2005 is consistent with the company's strong performance year in 2005. The result was a payout factor of 200% for the annual incentive program. The less dramatic movement in our share price in subsequent years is partially reflected by our payout factors declining to 120% in 2006 and 88% in 2007. As indicated by the downward movement in the graph, the turbulence in the global financial markets in 2008 has impacted Nexen's share price, not unlike other publicly traded companies. While this is unfavorable, our share performance captured in this graph reflects a point in time and is generally consistent with organizations in our sector for 2008. In 2008, our performance exceeded target, including record financial results and strong relative share price performance. These successes were balanced by disappointing results from the Marketing division and impairment charges. The resulting payout factor for 2008 was 120%. For long-term incentives, the downward shift in our share price has significantly decreased the in-the-money value.

The following graph shows the change in a $100 investment in Nexen common shares over the past five years, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index as at December 31, 2008. Our common shares are included in each of these indices.



Total Return Index Values [1]

	2003/12	2004/12	2005/12	2006/12	2007/12	2008/12
Nexen Inc.	100.00	104.63	239.28	278.11	279.00	187.59
S&P/TSX Oil & Gas Exploration & Production Index	100.00	140.68	244.28	247.51	272.59	188.70
S&P/TSX Energy Sector Index	100.00	130.29	212.94	225.84	244.43	161.63
S&P/TSX Composite Index	100.00	114.48	142.10	166.63	183.01	122.61

1 *Assuming an investment of $100 and the reinvestment of dividends.*

Share Ownership Guideline

All executive officers demonstrate their commitment to Nexen by holding more shares than required under our board-approved guideline. Shares must be accumulated within five years from the date the executive was appointed. Share ownership includes the net value of exercisable options or TOPs, flow-through shares, shares purchased and held within the Nexen employee savings plan and any other personal holdings. The guideline is reviewed periodically by the Compensation Committee and the board. See page 153 for the current share ownership of each executive.

Position	Required Share Ownership
CEO	Three times annual salary
CFO	Two times annual salary
Other executive officers	One times annual salary

Long-Term Incentives

Nexen's long-term incentive program, the TOPs and StARs plans, provide employees with a long-term incentive to sustain high performance, demonstrate commitment to Nexen and, most importantly, align their interests with those of our shareowners. As Nexen's share price rises, grants increase in value. TOPs or StARs are granted to employees, based on internal organization levels, whose actions can most directly impact our business results. Named executives are granted TOPs.

In determining the number of TOPs and StARs to grant each year, Nexen considers the program's dilutive impact on shareowners and market information on stock options and other forms of long-term incentives. Market information also determines the extent to which employees at different levels participate in the program. The Compensation Committee reviews and recommends TOPs plan amendments for the board to approve. Management and the Compensation Committee continue to consider alternative long-term incentive programs used by our peers, including full-value plans such as DSUs, restricted share units and performance-based stock options. At this time, TOPs and StARs continue to best meet Nexen's objectives, considering competitive position, retention value, tax effectiveness for both our employees and Nexen, shareowner interests, and dilution levels.

TOPs Plan

Our TOPs plan has been in place since 2004. It allows employees to either:

- exchange their vested TOPs for a cash payment equal to the difference between the grant price and the closing market price of our common shares on the date the TOPs were exchanged; or
- exercise their TOPs for shares. Nexen common shares are issued for TOPs on a one-for-one basis.

When employees exchange their TOPs for cash: (i) no shares are issued, which prevents further shareowner dilution over time; and (ii) Nexen receives a Canadian income tax deduction.

2008 TOPs Plan Exercises and Exchanges

Total Exercised or Exchanged	Exercised for Shares	Exchanged for Cash
5,749,570	1,910,488 (33%)	3,839,082 (67%)

TOPs do not provide employees with the right to vote the underlying shares. The TOPs plan is Nexen's only equity-based compensation arrangement for the purposes of disclosure requirements.

The board, on the recommendation of the Compensation Committee, may grant TOPs to Nexen officers and employees. TOPs granted before February 2001 have a term of ten years; 20% of the grant vested after six months and 20% vested each year for four years on the grant's anniversary. TOPs granted after February 2001 have a term of five years and vest one-third each year for three years. The board has the discretion to set vesting periods within the five-year term. To allow for the exceptional circumstances of the retirement of Nexen's CEO in 2008, the CEO's 2008 TOPs grant was reduced and the vesting set at one-half each year for two years. Normal retirement provisions in the plan apply and will result in the expiry and cancellation of 50% of this grant.

Generally, if a change of control event occurs (as defined in the TOPs plan), all issued but unvested options will vest.

StARs Plan

The StARs plan, introduced in 2001, provides a cash payment to participants equal to the appreciation in Nexen's share price between the date the StARs are granted and the date they are exercised. StARs are typically granted to employees below mid-level department manager. They have a five-year term and vest one-third each year for three years.

Grant Date and Exercise Price

TOPs and StARs are granted during the annual grant process and at the time of hiring key positions. Since 1998, the annual grants have been approved at the December board meeting. According to our plans, the CEO can approve grants to key new hires and typically they occur shortly after the hire date. Under the plans, the exercise price is the closing market price of Nexen's common shares on the relevant stock exchange (TSX for Canadian-based employees or NYSE for US-based employees) on the day before the grant is approved. Accordingly, backdating is not allowed. Nexen's grants are not intentionally timed to occur immediately prior to the release of material information (spring-loaded). The exercise price of existing TOPs or StARs may not be reduced except for automatic adjustments, such as a share split, or according to TSX rules. Accordingly, repricing is not allowed.

Options Outstanding and Shares Reserved for Issue

We limit the combined annual grants of TOPs and StARs (even though StARs are not dilutive) to less than 2% of total outstanding shares (on a non-diluted basis). The total TOPs granted, plus shares reserved for future issue under equity-based compensation programs, will not exceed 10% of our total outstanding shares (on a non-diluted basis). Since the implementation of the tandem feature in 2004, 9,788,475 shares have been issued at December 31, 2008, representing 1.9% dilution.

Grants in the Last Three Years

Our 2008 long-term incentives recognized employees for high performance, future potential within Nexen and retention risk.

Year	Granted to Executive Officers	Granted to Employees	Percentage of Employees Receiving Grants	Total Number Granted
TOPs				
2008	1,526,000	2,008,100	6%	3,534,100
2007	1,735,000	2,272,100	7%	4,007,100
2006 [1]	1,480,000	3,321,000	7%	4,801,000
StARs				
2008	–	4,917,200	53%	4,917,200
2007	–	4,194,600	54%	4,194,600
2006 [1]	–	4,508,600	51%	4,508,600

1 Numbers of TOPs and StARs granted have been adjusted to account for Nexen's two-for-one share splits in May 2005 and May 2007.

Benefit and Pension Plans

Our benefit and pension plans support the health and well-being of our employees, and encourage retirement savings. The plans are reviewed periodically to ensure they remain competitive and continue to meet our objectives. Market survey data is reviewed to ensure the plans provide benefits between the 50th and 75th percentile of plans within our peer group. Executives participate in the same plans provided to all employees at the same location.

Disclosure in this document is specific to the Canadian plans in which the executives participate. Nexen provides a variety of other benefit and pension plans outside of Canada that reflect local market practices.

Health and Welfare Benefits

Our benefit plans are designed to protect employees' health and that of their dependants, and cover them in the event of disability or death. Under the flexible benefit plans, employees choose the level of coverage that best fits their needs. Those who select enhanced coverage levels are required to contribute to the cost of that coverage.

Employee Savings Plan

To help employees save for their future and encourage ownership in the company, Nexen provides the incentive and opportunity to accumulate savings through an employee savings plan. In the plan, all eligible Canadian employees may contribute, through payroll deduction, any percentage of their base salary to purchase Nexen common shares, mutual fund units or a combination of both. Nexen matches employee contributions up to 6% of base salary, depending on the investment option and how long the employee has participated in the plan. Nexen contributions are invested in our common shares purchased on the open market and vest immediately. All contributions may be allocated to registered or non-registered accounts. Employees may vote the Nexen common shares they hold in their employee savings plan.

Defined Benefit Pension Plan

Canadian employees of Nexen elect, upon hire, to participate in either the defined contribution pension plan or the defined benefit pension plan, both of which are registered. All named executives participated in the defined benefit pension plan in 2008. Features of the plan are:

- participant contributions at 3% of their regular gross earnings (up to an annual plan maximum);
- retirement benefits at 1.8% (1.7% for years prior to 2005) of their average earnings for the 36 highest-paid consecutive months during the 10 years before retirement, multiplied by the years of credited service;
- integration with Canada Pension Plan (CPP) to provide a maximum offset of one-half of the current CPP benefit, prorated by years of credited service to a maximum of 35 years;
- benefits on retirement that are generally paid monthly for the life of the retiree, subject to payment elections;
- members who retire after 10 years of service are eligible for an early retirement benefit at age 55, with a 4% per year early retirement reduction for each year that benefits commence prior to age 60; and
- ability for participants to periodically switch between the defined benefit pension plan and defined contribution pension plan at different stages in their career.

Plan participants may annually elect to increase their defined benefit accrual formula from 1.8% to 2%. Employees who choose this option must contribute an additional 2% of pensionable earnings up to an allowable maximum under the Canadian

Income Tax Act. The maximum employee contribution allowed under the defined benefit pension plan in 2008 was $11,200.

The normal form of benefit paid is a joint life and survivor benefit with a five-year guarantee. It is payable for the participant's lifetime and provides the spouse with a survivor benefit of 66⅔% of the monthly payment. If the participant dies before receiving 60 monthly payments, the five-year guarantee allows the surviving spouse to receive the balance of the 60 monthly payments first and then the reduced survivor pension of 66⅔%.

Pension benefits earned prior to January 1, 1993 may be indexed at the discretion of management's pension committee, considering increases in the consumer price index. Pension benefits earned after December 31, 1992 are indexed annually between 0 and 5% based on the greater of:

- 75% of the increase in the consumer price index, less 1%; and
- 25% of the increase in the consumer price index.

Pension Benefit Obligation

At December 31, 2008, as indicated in the notes to our Consolidated Financial Statements, the:

- registered pension plan's accumulated benefit obligation (the projected benefit obligation, excluding future salary increases) for the defined benefit plan was $179 million, which includes all active and inactive plan participants; and
- projected benefit obligation was $203 million.

The projected benefit obligation is an accounting-based value of the contractual entitlements that will change over time. The method used to determine this estimate will not be identical to those used by others and, as a result, the estimate may not be directly comparable across companies. The key assumptions used for the projected benefit obligation were:

- a discount rate of 5.25% per year as at December 31, 2007;
- a discount rate of 6.5% per year as at December 31, 2008;
- a long-term compensation rate increase of 4% per year; and
- an assumed rate of inflation of 2.5% per year.

Executive Benefit Plan

The executive benefit plan is available to all Canadian employees. It provides supplemental retirement benefits for either defined benefit or defined contribution participants who have earned a retirement benefit in excess of the statutory limits, which varies by employees' pension elections. This allows employees to fully accrue a pension that is aligned with their earnings level and is competitive within our market. For defined benefit plan participants, any supplemental benefits will accrue and be paid monthly in a similar manner to the underlying defined benefit pension plan set out above on pages 145 and 146. For executives, annual cash incentive payments during the last three years of plan participation are included for benefit accrual purposes based on the lesser of target bonus or actual bonus paid.

Pension Benefit Security

The pension expense for this supplemental plan is accounted for annually. Benefits are paid from Nexen's cash flows and reduce the related pension liability. As liabilities under this plan are unfunded, a level of protection is provided to participants through a letter of credit. The letter of credit is intended to make participants secured creditors for the unfunded pension obligation under the executive benefit plan. The cost of servicing the letter of credit in 2008 for all plan participants was $917,237.

Pension Benefit Obligation

At December 31, 2008, as indicated in the notes to our Consolidated Financial Statements, the:

- supplemental pension plan's accumulated benefit obligation (the projected benefit obligation, excluding future salary increases) for the executive benefit plan was $49 million, which includes all active and inactive plan participants; and
- projected benefit obligation was $62 million.

The projected benefit obligation and key assumptions used for the projected benefit obligation are the same as those used for the registered pension plan.

As of January 1, 2005, the executive benefit plan was amended to provide a supplemental pension allocation for defined contribution pension plan participants who are impacted by annual statutory contribution limits. In 2008, the sum of all supplemental allocations for eligible participants was $50,061 and is estimated to be $53,000 in 2009.

Retirement Benefits

All Nexen retirees are provided with retirement benefits that consist of a $5,000 life insurance policy and reimbursement for provincial healthcare premiums, if applicable.

Loans to Officers

As set out in the corporate governance policy, we do not make loans to officers. There are no loans outstanding from Nexen to any of its officers.

EXECUTIVE OFFICERS

The board determines the term of office for each executive officer. Below are Nexen's officers, including prior offices and non-executive positions for officers who have held their current executive positions with Nexen for less than five years. Start dates are indicated for officer positions with Nexen.

Officer (Age)	**Current and Past Position(s) with Nexen**	**Effective Date of Current Position**	**Executive Officer Since**
Marvin F. Romanow (53)	President and CEO and a director. Formerly: Executive VP and CFO since June 1, 2001.	January 1, 2009	1997
Kevin J. Reinhart (50)	Senior VP and CFO. Formerly: Senior VP, Corporate Planning and Business Development since November 1, 2007. Formerly: VP, Corporate Planning and Business Development since July 11, 2002.	January 1, 2009	1994
Laurence Murphy (57)	Executive VP, International Oil and Gas. Formerly: Senior VP, International Oil and Gas since January 1, 1999.	November 1, 2007	1998
Roger D. Thomas (56)	Executive VP, North America. Formerly: Senior VP, Canadian Oil and Gas since February 19,1999.	November 1, 2007	1998
Gary H. Nieuwenburg (50)	Senior VP, Synthetic Crude. Formerly: VP, Synthetic Crude since July 11, 2002.	November 1, 2007	2001
Brian C. Reinsborough (47)	Senior VP, United States Oil and Gas. Formerly: Division VP, Exploration, Operations and Production since May 12, 2006; Division VP, Exploration since July 8, 2002.	November 1, 2007	2007
Timothy J. Thomas (51)	Senior VP, Canadian Oil and Gas. Formerly: Division VP, Exploration and Production, Canadian Oil and Gas since April 1, 2004; Division VP, Yemen Operations and International Business Development since January 1, 2003.	November 1, 2007	2007
Randy J. Jahrig (53)	VP, Human Resources and Corporate Services. Formerly: Division VP, Human Resources Canada and International since April 1, 2002.	April 26, 2007	2007
Kim D. McKenzie (60)	VP and Chief Information Officer. Formerly: Division VP, Information Technology since January 1, 1992.	November 1, 2007	2007
Eric B. Miller (46)	VP, General Counsel and Secretary. Formerly: Division VP and Chief Legal Counsel since July 1, 2006; Division VP, Legal Canadian Oil and Gas since March 1, 2002.	July 11, 2007	2007
Una M. Power (44)	VP, Corporate Planning and Business Development. Formerly: Treasurer since July 11, 2002.	January 16, 2009	1998
Brendon T. Muller (40)	Controller. Formerly: Manager, Corporate External Reporting since November 1, 2003.	April 9, 2007	2007
J. Michael Backus (38)	Treasurer. Formerly: Manager, Planning, Synthetic Crude since January 1, 2009; Project Planner – Phase 2 Long Lake, Synthetic Crude since April 1, 2005; Analyst, Investor Relations and Corporate Communications since April 1, 2003.	February 16, 2009	2009

SHARE SPLITS

All grant prices and numbers granted have been adjusted to account for the May 2005 and May 2007 share splits.

SUMMARY COMPENSATION TABLE

To determine the next three highest paid officers, after the CEO and CFO, we total their salary, special bonus, non-equity cash incentive plan compensation, long-term incentive compensation and all other compensation as shown below. Grants of TOPs are considered option-based awards under applicable disclosure requirements. We do not award share-based awards or non-equity incentive plan compensation under long-term incentive plans, as these terms are used in applicable disclosure requirements.

			Option-Based					
Name and Principal Position	Year	Annual Salary ($)	TOPs Awards (#)	TOPs Value [2] ($)	Non-Equity Incentive Plan Compensation [1, 3] ($)	Pension Value [4] ($)	All Other Compensation [5] ($)	Total Compensation ($)
Charles W. Fischer,	2008	1,348,750	400,000 [6]	2,245,760	1,500,000	938,800	124,245	6,157,555
(Retired) President	2007	1,275,000	600,000	5,110,200	916,000	949,300	119,640	8,370,140
and CEO	2006	1,150,000	550,000	5,010,654	1,800,000	1,673,800	111,621	9,746,075
Marvin F. Romanow, [7]	2008	601,250	475,000	2,747,514 [8]	700,000	317,800	119,016	4,485,580
Executive VP	2007	566,250	180,000	1,533,060	330,000	323,300	117,129	2,869,739
and CFO	2006	528,000	160,000	1,457,645	402,000	534,800	118,073	3,040,518
Laurence Murphy,	2008	546,250	170,000	921,536	400,000	285,800	60,508	2,214,094
Executive VP,	2007	495,833	165,000	1,405,305	303,000	583,300	57,214	2,844,652
International Oil & Gas	2006	455,000	130,000	1,184,336	642,000	580,800	53,711	2,915,847
Roger D. Thomas,	2008	542,500	170,000	921,536	436,000	265,800	60,188	2,226,024
Executive VP,	2007	487,500	165,000	1,405,305	275,000	792,300	56,690	3,016,795
North America	2006	445,000	130,000	1,184,336	336,000	735,800	53,086	2,754,222
Gary H. Nieuwenburg,	2008	416,500	100,000	542,080	365,000	141,800	52,670	1,518,050
Senior VP,	2007	360,667	100,000	851,700	191,000	267,300	48,775	1,719,442
Synthetic Crude	2006	328,850	100,000	911,028	210,000	284,800	51,944	1,786,622

1 *Reflects the value of awards earned in each year under Nexen's annual cash incentive program. The awards are paid to the executives in the following calendar year based on their salary on December 31 of the previous year.*

2 *Reflects the estimated fair value under the Black-Scholes pricing model of TOPs granted in the year. The key assumptions of this valuation include current market price of the stock, exercise price of the option, option term, risk-free interest rate, turnover, dividend yield of stock and volatility of stock return. The actual value realized will depend on the Nexen share price at the time of exercise. The accounting fair value is calculated using the intrinsic value method, which is the difference between the market price of the stock and the exercise price of the option. The difference between these valuation methods is the TOPs value included in this column as the intrinsic value was nil at year end. Management's consultant provides the annual Black-Scholes value. There were no amendments to the exercise price of TOPs in 2008.*

3 *For Messrs. Fischer, Romanow, Thomas and Nieuwenberg, includes discretionary recognition in 2008 for a variety of critical business initiatives. For Messrs. Fischer and Murphy, includes a discretionary award in 2006 for the success of Buzzard of $500,000 and $300,000, respectively.*

4 *Represents the current service cost, less required member contributions to the plan, plus changes in compensation in excess of actuarial assumptions.*

5 *The total value of the perquisites portion of All Other Compensation provided to each executive is less than $50,000 and less than 10% of their annual salary. See the table on page 155 for details of these amounts.*

6 *TOPs awarded to Mr. Fischer in 2008 have a two-year vesting period. As vested TOPs can be exercised up to 18 months after retirement, 50% of this grant will expire and be cancelled in accordance with the provisions of the plan.*

7 *Mr. Romanow is a director of Canexus and was paid fees of $34,000, received notional deferred trust units of Canexus valued at $15,600 and distributions on his trust units of $6,399 in 2008. In 2007, he was paid fees of $32,500, received notional deferred trust units of Canexus valued at $19,560 and distributions on his trust units of $4,259. In 2006, he was paid fees of $34,000, received notional deferred trust units of Canexus valued at $24,000 and distributions on his trust units of $2,571. These amounts are included in the All Other Compensation table on page 155.*

8 *Mr. Romanow was appointed President and CEO effective January 1, 2009 and received a grant of 295,000 TOPs upon appointment. The TOPs value of this grant is $1,771,770 and the value of the 180,000 TOPs granted on December 8, 2008 is $975,744.*

Changes in Compensation Arrangements in 2008

We did not introduce any new compensation or benefit program in 2008 for Nexen's named executives.

As seen in the table above, the December 2008 TOPs awards expected values have decreased from the prior years. While Nexen's share price was falling during the time of grant, we did not feel it was necessary to increase the grant size to maintain the expected value year-over-year. Our 2008 program was designed with a long-term perspective of share value and to avoid unintended windfall when financial markets recover.

The compensation paid to executives in 2008 is consistent with our philosophy and objectives of targeting total compensation between the 50th and 75th percentile as detailed on pages 139 through 142.

Changes in Pension Obligations

The Summary Compensation Table shows the year-over-year change in pension obligations. The value reflects the employer service cost, plus any changes in obligations resulting from compensation increases over actuarial assumptions, less required member contributions to the plan. Actual compensation changes may vary from the assumed rate of compensation increase and will vary among each executive from year to year. These values differ from the termination values reported under the change of control agreements on page 156 which disclose additional lump sum pension benefits provided if a change of control occurs.

CEO COMPENSATION AND 2008 GOALS AND RESULTS

The CEO's responsibility is to provide leadership in setting and achieving goals that create value for our shareowners in the short and long term. Mr. Fischer's 2008 annual cash incentive award was based on the corporate results described on pages 141 and 142, which determined the total cash available for the awards. Cash incentive awards are determined from the available pool and distributed to individuals based on specific annual goals. Based on the board's assessment of Mr. Fischer's achievement of objectives, and their positive assessment of his contribution to continued shareowner value growth and strategic plan execution, he was awarded an annual cash incentive of $1,500,000, which is his target bonus times 137%. The incentive includes discretionary recognition for a number of critical business initiatives in the year. Mr. Fischer's 2008 goals and results are outlined below.

Develop and implement a corporate strategy, balancing short-term growth while positioning Nexen for sustainable growth.

In 2008, Mr. Fischer once again led the management team in a review of our strategic plan, which is focused on creating long-term sustainable growth. Out of this review, the annual operating plan was developed and subsequently approved by the board. In 2008, 45% of oil and gas capital was invested in next generation, new growth projects such as the Usan development offshore West Africa, shale gas, CBM, future oil sands phases and conventional exploration. These investments support a long-term strategy for sustainable growth.

Achieve capital, operating, and general and administrative cost performance targets set out in the annual operating plan (AOP).

Mr. Fischer demonstrated his ability to manage costs successfully in 2008 despite the volatile economic environment. The majority of Nexen's production has low operating costs and low royalties. This is generating cash netbacks that are among the highest in the industry. As a result, our assets are capable of generating positive cash flows despite recent declines in commodity prices.

Capital investments in 2008 of approximately $2.5 billion in oil and gas exploration and development activities added 74 mmboe of proved reserves before negative economic revisions of 50 mmboe. Many of our projects are characterized by multi-year investments where capital is invested, in some instances, years before reserves can be recognized. Measuring proved reserves additions against capital expenditures for a one-year period, and in some cases a three-year period, is not meaningful and does not tell the whole Nexen story.

Achieve targets for operating cash flow, earnings, production levels, and reserve replacement set out in the AOP.

In 2008, under Mr. Fischer's leadership, Nexen generated record cash flow in excess of $4.2 billion and earnings of approximately $1.7 billion despite losses incurred by the Marketing division and impairment charges. The Marketing division reported significant cash flow losses in 2008. Nexen has exited positions that do not support its physical marketing business, which was challenging given the lack of liquidity in the market, fewer counterparties and deteriorating commodity prices. Earnings in 2008 were impacted by an impairment charge of $317 million (after tax) relating to oil and gas properties in the Gulf of Mexico and the North Sea. These properties were written down to their fair value, based on the estimated total future discounted net cash flows. Production levels reflected a modest increase over 2007 despite hurricane downtime.

Maintain financial flexibility and liquidity to support our business strategies.

With Mr. Fischer's direction, we achieved better than target results related to financial flexibility and liquidity. In 2008, cash flow exceeded capital investment by over $1 billion. This excess was used to repurchase approximately 12 million shares for $338 million and build cash balances. A portion of this cash was used to fund the acquisition of an additional 15% in the

Long Lake Project and joint venture lands. Nexen has no debt maturities until 2012 and the average term of its public debt is approximately 18 years. We are well positioned to weather the downturn in the economy given our strong liquidity.

Achieve top-quartile performance in health, safety and environmental performance and social responsibility.

Mr. Fischer is highly committed to social responsibility. Nexen improved its employee injury rates over 2007, just missing its best ever results set in 2006. There were no major environmental incidents in the year. Nexen continues to be recognized as a social responsibility leader and was included again in the Dow Jones Sustainability Index for 2008.

Provide for corporate management succession and development.

Mr. Fischer led the review of Nexen's succession plan in 2008 and demonstrated its effectiveness as we were able to fill the vacancies related to his retirement entirely with internal candidates.

Ensure Nexen adheres to the highest standards of integrity.

Mr. Fischer sets a high standard for integrity in the workplace. Nexen continued to emphasize the importance of integrity among its employees, 93% of whom attended our integrity workshop by the end of 2008.

Demonstrate his personal commitment to community and industry leadership.

Mr. Fischer filled numerous leadership roles in the community and industry. These personal and professional commitments involved a variety of organizations including the Alberta Children's Hospital Foundation, Calgary Airport Authority, Hull Child and Family Services, Alberta Energy Research Institute and the Institute for Sustainable Energy, Environment and Economy (University of Calgary).

CEO THREE-YEAR LOOK-BACK

	Three-Year Total	2008	2007	2006
Cash				
Base Salary	3,773,750	1,348,750	1,275,000	1,150,000
Annual Cash Incentive [1]	4,216,000	1,500,000	916,000	1,800,000
Equity				
Value of TOPs [2]	12,366,614	2,245,760	5,110,200	5,010,654
Total Direct Compensation	**20,356,364**	**5,094,510**	**7,301,200**	**7,960,654**
All Other Compensation [3]	355,506	124,245	119,640	111,621
Pension Value [4]	3,561,900	938,800	949,300	1,673,800
Total Cost	**24,273,770**	**6,157,555**	**8,370,140**	**9,746,075**
Annual Average	8,091,257			
Total Market Capitalization Growth ($millions)	(3,340)	(5,800)	90	2,370
Total Cost as a % of Market Capitalization Growth [5]	(0.73)%			

1 Includes discretionary recognition in 2008 for a number of critical business initiatives and $500,000 in 2006 for the success of Buzzard.
2 Reflects the estimated fair value of TOPs using the Black-Scholes pricing model valued on the grant date. See page 148 for details of this calculation.
3 See page 155 for details of All Other Compensation.
4 Represents the current service cost, less required member contributions to the plan, plus changes in compensation in excess of actuarial assumptions.
5 The current global financial situation changes the context of this metric, reducing its associated meaning.

In 2008, the Compensation Committee reviewed look-back information and analyzed Mr. Fischer's total pay and shareowner value created from the date he became CEO. In the analysis, dollar values were assigned and tallied for each compensation component including salary, annual cash incentives, TOPs awards, benefits, pension and potential payments on change of control. The Committee reviewed his total compensation relative to Nexen's market capitalization and that of industry peers.

INCENTIVE PLAN AWARDS

To value incentive plan awards (TOPs), Nexen uses the Black-Scholes pricing model, which is a generally accepted method for measuring this type of long-term incentive. The actual value realized on exercises may be higher or lower depending on the Nexen share price at the time of exercise.

Incentive Plan Awards Granted in 2008

The term for TOPs granted in 2008 is five years and vesting is one-third each year for three years. Mr. Fischer's grant vests over two years with 50% vesting on each anniversary. Our plans allow retirees to exercise vested TOPs up to 18 months after retirement. This means that 50% of the grant will expire and be cancelled prior to vesting under these circumstances and he will never be able to exercise them. Mr. Fischer received that component of his annual compensation (despite its long-term nature) due to his sustained high performance and his leadership on many initiatives during the year that created sustainable future value.

							Potential Realizable Value at Assumed Annual Rates of Share Price Appreciation for TOPs Term	
Name	Grant Date	TOPs Granted (#)	% of Total TOPs Granted to Employees	Exercise Price ($)	Expiry Date	TOPs Value[2] ($)	5% ($)	10% ($)
Fischer	Dec. 8, 2008	400,000	10.3%	19.36[1]	Dec. 7, 2013	2,245,760	2,139,524	4,727,789
Romanow	Dec. 8, 2008	180,000	4.6%	19.36[1]	Dec. 7, 2013	975,744	962,786	2,127,505
	Jan. 2, 2009[3]	295,000	7.6%	21.45	Jan. 1, 2014	1,771,770	1,748,241	3,863,155
Murphy	Dec. 8, 2008	170,000	4.4%	19.36[1]	Dec. 7, 2013	921,536	909,298	2,009,311
Thomas	Dec. 8, 2008	170,000	4.4%	19.36[1]	Dec. 7, 2013	921,536	909,298	2,009,311
Nieuwenburg	Dec. 8, 2008	100,000	2.6%	19.36[1]	Dec. 7, 2013	542,080	534,881	1,181,947

1 Reflects the closing market price of Nexen common shares on the TSX on December 5, 2008.

2 Reflects the estimated fair value of the TOPs as at December 8, 2008 using the Black-Scholes pricing model. See page 148 for details of this calculation.

3 Mr. Romanow received this grant upon his appointment as President and CEO. The exercise price is the closing market price of Nexen common shares on the TSX on December 31, 2008.

Incentive Plan Awards – TOPs Exercised or Exchanged and Value Vested or Earned in 2008

The TOPs value realized in 2008 occurred within two months of grant expiry, demonstrating that executives are holding TOPs for the long-term, in alignment with our long-term strategy. The TOPs value vested in 2008 represents what could have been earned if executives exercised TOPs immediately upon vesting. As shown in the table, the TOPs awards vesting in 2008 had no in-the-money value upon vesting, resulting in a significant reduction in the value of outstanding TOPs awards. The actual value realized will depend on the share price at the time of exercise. Grants of TOPs are considered option-based awards under applicable disclosure requirements. We do not award named executives share-based awards or non-equity incentive plan compensation under long-term incentive plans, as these terms are used in applicable disclosure requirements.

	TOPs Awards		TOPs Awards		Non-Equity Incentive Plan Compensation
Name	Exercised or Exchanged (#)	Value Realized[1] ($)	Vested in 2008 (#)	Value Vested in 2008[2] ($)	Value Earned During the Year[3] ($)
Fischer	600,000	6,248,500	517,500	–	1,500,000
Romanow	220,000	3,217,500	154,920	–	700,000
Murphy	–	–	132,000	–	400,000
Thomas	128,000	1,112,960	132,000	–	436,000
Nieuwenburg	58,000	522,290	93,400	–	365,000
Total	**1,006,000**	**11,101,250**	**1,029,820**	–	**3,401,000**

1 Reflects the market price at the time of the exercise or exchange, minus the exercise price, as defined in the TOPs plan.

2 Reflects the market price at the time of vesting, minus the exercise price, as defined in the TOPs plan. All TOPs awards vesting in 2008 had an exercise price greater than the market price.

3 Represents compensation earned in 2008 and paid in 2009.

Outstanding Incentive Plan Awards

Name	Date Granted	Expiry Date	Exercise Price ($)	Granted[3] (#)	Vested and Unvested TOPs at Dec. 31, 2008[1,2] Number of Securities Underlying Unexercised TOPs (#)	Value of Unexercised TOPs[4] ($)	Vested TOPs at Dec. 31, 2008[2] Number (#)	Value[4] ($)
Fischer	Dec. 14, 1999	Dec. 13, 2009	6.8125	280,000	280,000	4,098,500	280,000	4,098,500
	Dec. 12, 2000	Dec. 11, 2010	9.0250	280,000	280,000	3,479,000	280,000	3,479,000
	Dec. 7, 2004	Dec. 6, 2009	12.7175	600,000	600,000	5,239,500	600,000	5,239,500
	Dec. 6, 2005	Dec. 5, 2010	27.2850	400,000	400,000	–	400,000	–
	Dec. 4, 2006	Dec. 3, 2011	31.6000	550,000	550,000	–	368,500	–
	Dec. 3, 2007	Dec. 2, 2012	28.3900	600,000	600,000	–	204,000	–
	Dec. 8, 2008	Dec. 7, 2013	19.3600	400,000	400,000	836,000	–	–
Total				**3,110,000**	**3,110,000**	**13,653,000**	**2,132,500**	**12,817,000**
Romanow[5]	Dec. 12, 2000	Dec. 11, 2010	9.0250	200,000	200,000	2,485,000	200,000	2,485,000
	Dec. 7, 2004	Dec. 6, 2009	12.7175	228,000	228,000	1,991,010	228,000	1,991,010
	Dec. 6, 2005	Dec. 5, 2010	27.2850	124,000	124,000	–	124,000	–
	Dec. 4, 2006	Dec. 3, 2011	31.6000	160,000	160,000	–	107,200	–
	Dec. 3, 2007	Dec. 2, 2012	28.3900	180,000	180,000	–	61,200	–
	Dec. 8, 2008	Dec. 7, 2013	19.3600	180,000	180,000	376,200	–	–
	Jan. 2, 2009	Jan. 1, 2014	21.4500	295,000	295,000	–	–	–
Total				**1,367,000**	**1,367,000**	**4,852,210**	**720,400**	**4,476,010**
Murphy	Dec. 7, 2004	Dec. 6, 2009	12.7175	160,000	52,800	461,076	52,800	461,076
	Dec. 6, 2005	Dec. 5, 2010	27.2850	100,000	100,000	–	100,000	–
	Dec. 4, 2006	Dec. 3, 2011	31.6000	130,000	130,000	–	87,100	–
	Dec. 3, 2007	Dec. 2, 2012	28.3900	165,000	165,000	–	56,100	–
	Dec. 8, 2008	Dec. 7, 2013	19.3600	170,000	170,000	355,300	–	–
Total				**725,000**	**617,800**	**816,376**	**296,000**	**461,076**
Thomas	Dec. 7, 2004	Dec. 6, 2009	12.7175	160,000	160,000	1,397,200	160,000	1,397,200
	Dec. 6, 2005	Dec. 5, 2010	27.2850	100,000	100,000	–	100,000	–
	Dec. 4, 2006	Dec. 3, 2011	31.6000	130,000	130,000	–	87,100	–
	Dec. 3, 2007	Dec. 2, 2012	28.3900	165,000	165,000	–	56,100	–
	Dec. 8, 2008	Dec. 7, 2013	19.3600	170,000	170,000	355,300	–	–
Total				**725,000**	**725,000**	**1,752,500**	**403,200**	**1,397,200**
Nieuwenburg	Dec. 7, 2004	Dec. 6, 2009	12.7175	120,000	120,000	1,047,900	120,000	1,047,900
	Dec. 6, 2005	Dec. 5, 2010	27.2850	80,000	80,000	–	80,000	–
	Dec. 4, 2006	Dec. 3, 2011	31.6000	100,000	100,000	–	67,000	–
	Dec. 3, 2007	Dec. 2, 2012	28.3900	100,000	100,000	–	34,000	–
	Dec. 8, 2008	Dec. 7, 2013	19.3600	100,000	100,000	209,000	–	–
Total				**500,000**	**500,000**	**1,256,900**	**301,000**	**1,047,900**

1 *Excludes grants that have been fully exercised.*

2 *The number and value of unvested TOPs can be determined by subtracting the vested TOPs from the vested and unvested TOPs. The value of unvested TOPs can be confirmed on page 156 in the Change of Control Table.*

3 *Nexen common shares are issued for TOPs on a one-for-one basis.*

4 *The difference between the market value of Nexen common shares on the TSX on December 31, 2008 of $21.45/share and the grant price of TOPs, times the number of TOPs. Where the grant price exceeds the market price of $21.45/share, the value shown is zero.*

5 *On January 2, 2009, Mr. Romanow was granted an additional 295,000 TOPs with an exercise price of $21.45/share upon his appointment as President and CEO.*

EQUITY OWNERSHIP AND CHANGES IN 2008

According to our share ownership guidelines, Mr. Fischer was required to hold three times his annual salary. Mr. Romanow is required to hold two times his annual salary, and the other executives are required to hold one times their annual salary.

	December 31, 2007		December 31, 2008		Net Change		Equity at Risk	
Name	**Shares**	**TOPs** [1]	**Shares**	**TOPs** [1]	**Shares**	**TOPs** [2]	**Value** [3] ($)	**Multiple of Salary** [4]
Fischer	183,426 [5]	2,215,000	602,417	2,132,500	418,991	(82,500)	25,738,845	19
Romanow	80,938	785,480	186,635	720,400	105,697	(65,080)	8,479,331	14
Murphy	125,226	164,000	135,016	296,000	9,790	132,000	3,357,169	6
Thomas	16,297 [5]	399,200	21,622	403,200	5,325	4,000	1,860,992	3
Nieuwenburg	65,795	265,600	77,016	301,000	11,221	35,400	2,699,893	6
Total	**471,682**	**3,829,280**	**1,022,706**	**3,853,100**	**551,024**	**23,820**	**42,136,230**	

1 *Represents total TOPs granted, vested and unexercised.*
2 *Reflects the number of TOPs that vested, minus the number exercised or exchanged during 2008.*
3 *Equity at risk is the market value of common shares and vested TOPs using the closing price of Nexen shares on the TSX on December 31, 2008 of $21.45/share.*
4 *Reflects the equity at risk, divided by the executive's 2008 salary amount shown on page 148.*
5 *Includes accumulations under the dividend reinvestment plan of ten common shares for Mr. Fischer and 70 common shares for Mr. Thomas which were not previously reported.*

PENSION PLAN TABLES

All executives are members of Nexen's registered defined benefit pension plan and executive benefit plan and accrue a pension benefit at a 2% accrual rate. With this option, they must contribute 5% of pensionable earnings up to the maximum allowed under the *Canadian Income Tax Act*. See pages 145 and 146 for details.

Pension Value Earned and Benefit Obligation Changes in 2008

Our reported values use actuarial assumptions and methods that are the same as those used to calculate pension obligations and the related annual expense disclosed in our Consolidated Financial Statements. As the assumptions reflect our best estimate of future events, our reported values may not be directly comparable to similar pension liability values disclosed by other companies.

The board must approve additional past service credits or accelerated service credits. No accelerated service credits were authorized in 2008. The notes to the table below show additional past service credits authorized by the board for the executives who participate in the Canadian defined benefit pension plan and the executive benefit plan.

No benefit payments were made to executives in the last fiscal year.

Defined Benefit Plan Table

Name	Years of Credited Service (#)	Annual Benefits Payable At Year End[1] ($)	At Age 65[2] ($)	Accrued Obligation at Jan. 1, 2008 ($)	Compensatory Change[3] ($)	Non-Compensatory Change[4] ($)	Change in Obligation since Dec. 31, 2007 ($)	Accrued Obligation at Dec. 31, 2008 ($)
Fischer	24.58[5]	904,792	1,168,001	12,660,000	938,800	(1,273,800)	(335,000)	12,325,000
Romanow	21.50[5,6]	368,527	572,458	4,722,000	317,800	(692,800)	(375,000)	4,347,000
Murphy	22.67	299,475	411,434	4,041,000	285,800	(390,800)	(105,000)	3,936,000
Thomas	28.50[5]	364,081	496,656	5,110,000	265,800	(535,800)	(270,000)	4,840,000
Nieuwenburg	4.00[7]	104,155	260,298	1,226,000	141,800	(225,800)	(84,000)	1,142,000
Total		**2,041,030**	**2,908,847**	**27,759,000**	**1,950,000**	**(3,119,000)**	**(1,169,000)**	**26,590,000**

1 *All information is as of December 31, 2008. Represents the sum of the benefits accrued under the defined benefit and executive benefit pension plans.*

2 *Represents a value based on projected years of credited service, a 2% accrual rate to age 65, and actual pensionable earnings used to calculate the benefit amount in the previous column of defined contribution service.*

3 *Includes the 2008 current service cost, less required member contributions to the plan, plus changes in compensation in excess of actuarial assumptions. Disclosure of the valuation method and significant assumptions used are found in the pension and other post-retirement benefits note 14 in our Consolidated Financial Statements.*

4 *Reflects the impact of interest on prior year's obligations, changes in discount rates used to measure the obligations and the impact of assumption and employee demographic changes.*

5 *Ten years of additional past service credits were granted to each of Messrs. Fischer, Romanow and Thomas by the board in 2001. This was a competitive practice to recognize that they were at a certain level in their career in 2001 when they were appointed to new positions.*

6 *Mr. Romanow joined the defined benefit pension plan after 7.25 years in the defined contribution pension plan. A pension benefit, which is reflective of base salary, will be based on his 21.50 years of defined benefit pension plan service. A pension benefit, which is reflective of pensionable bonus, will also be based on 28.75 years of service, which includes the 7.25 years of defined contribution service.*

7 *Mr. Nieuwenburg joined the defined benefit pension plan after 23.58 years in the defined contribution pension plan. A pension benefit, which is reflective of base salary, will be based on his 4 years of defined benefit pension plan service. A pension benefit, which is reflective of pensionable bonus, will also be based on 27.58 years of service, which includes the 23.58 years of defined contribution service.*

The information in the following table is a supplement to the previous table. The final average earnings reported for each named executive are used in the respective calculations and are based on the:

- average base salary for the 36 highest-paid consecutive months during the ten years up to December 31, 2008; plus
- annual cash incentive payments at the lesser of the target bonus or actual bonus paid, averaged over the final three years of participation up to December 31, 2008.

	Years of Credited Service				Accrued Annual Pension Benefit[1]		Estimated Annual Pension Benefit at Age 60[2]	
Name	Up to Dec. 31, 2004 (#)	From Jan.1, 2005 (#)	Total (#)	Final Average Earnings ($)	Under the Defined Benefit Pension Plan ($)	Under the Executive Benefit Plan ($)	Under the Defined Benefit Pension Plan ($)	Under the Executive Benefit Plan ($)
Fischer	20.58	4.00	24.58	2,113,250	34,028	870,765	38,704	918,730
Romanow	17.50	4.00	21.50	881,567	26,833	341,694	44,407	440,652
Murphy	18.67	4.00	22.67	762,361	52,889	246,586	61,315	274,641
Thomas	24.50	4.00	28.50	742,000	43,167	320,915	55,000	367,835
Nieuwenburg	–	4.00	4.00	525,182	9,333	94,822	34,426	174,112

1 *All information is as of December 31, 2008.*

2 *Represents a value based on projected years of credited service at a 2% accrual rate at age 60 and actual pensionable earnings used to calculate the accrued annual pension benefit values in the previous column. Age 60 is the earliest age an individual can receive unreduced retirement benefits.*

Defined Contribution Plan Table

The following table represents the value of accumulated pension assets within the registered defined contribution pension plan. Under the terms of this plan, all benefits have been funded. The individuals were entitled to benefits under this registered plan prior to being appointed to executive positions at Nexen. The individuals have no entitlements under any supplemental defined contribution pension plan arrangement and there is no above-market or preferential earnings provisions.

The two individuals are active participants of the defined benefit pension plan and have not contributed to or received any company-provided benefits under the terms of this plan for more than four years as indicated in the notes below.

Name	Accumulated Value at Jan. 1, 2008	Compensatory	Non-Compensatory	Accumulated Value at Dec. 31, 2008
Romanow [1]	437,608	–	(105,967)	331,641
Nieuwenburg [2]	542,061	–	(131,260)	410,801

1 Mr. Romanow joined the defined benefit pension plan in 1997 after 7.25 years in the defined contribution pension plan.
2 Mr. Nieuwenburg joined the defined benefit pension plan in 2005 after 23.58 years in the defined contribution pension plan.

ALL OTHER COMPENSATION

The total value of perquisites provided to any executive was less than $50,000 and less than 10% of the executive's annual salary in 2008. Certain perquisites shown below are at the maximum reimbursable amount available to executives. This maximum is often higher than what the executive actually claimed in the year. These perquisites are not available to the broader employee population.

	Perquisites			Other Compensation				
Name	Car Allowance	Other Perquisites [1]	Total	Life Insurance Premiums [2]	Savings Plan Contributions	Amounts Paid by Canexus [3]	Total	Total All Other Compensation
Fischer	31,200	10,500	41,700	1,620	80,925	–	82,545	124,245
Romanow	19,200	7,100	26,300	642	36,075	55,999	92,716	119,016
Murphy	19,200	7,100	26,300	1,433	32,775	–	34,208	60,508
Thomas	19,200	7,100	26,300	1,338	32,550	–	33,888	60,188
Nieuwenburg	19,200	7,100	26,300	1,380	24,990	–	26,370	52,670

1 Represents a maximum reimbursement amount for financial counselling, luncheon club memberships, medical exam and security monitoring. For the CEO, this also includes a maximum reimbursement amount for a golf club membership.
2 The life insurance premiums provided to the executive are made available to all employees.
3 Includes fees for serving as a director of Canexus of $34,000, deferred trust units of Canexus valued at $15,600 and distributions on his trust units of $6,399.

TERMINATION AND CHANGE OF CONTROL BENEFITS

Nexen does not enter into employment service contracts. Depending on the conditions of termination, we treat executives and employees fairly as follows:

Event	Action
Resignation	• All salary and benefit programs cease • Annual incentive bonus is not paid • TOPs must be exercised within 90 days • Pension paid as a commuted value or deferred benefit
Retirement	• Salary and benefit coverages cease except for a $5,000 life insurance policy • Monthly benefit to cover the cost of provincial health care premium continues in certain jurisdictions • Annual incentive bonus paid on a pro-rata basis • TOPs must be exercised within 18 months • Pension paid as a monthly benefit
Death	• All salary and benefit programs cease except for a one-year benefit coverage for surviving dependants and payout of any applicable insurance benefits • Annual incentive bonus paid on a pro-rata basis • TOPs must be exercised within 18 months • Pension paid as a commuted value or deferred benefit
Termination without cause	• All salary and benefit programs cease • TOPs must be exercised within 90 days • Pension paid as a commuted value or deferred benefit • Severance provided on an individual basis reflecting service, age and salary level
Termination for cause	• All salary and benefit programs cease • Annual incentive bonus is not paid • TOPs must be exercised on termination • Pension paid as a commuted value or deferred benefit

Payments on Resignation

The following table discloses the lump sum value of pension benefits accrued under the defined benefit pension plan and executive benefit plan for our named executives had they resigned effective December 31, 2008. If they are over the age of 55 and have at least 10 years of Nexen service, they are deemed to have retired and a lump sum benefit option is not available. Also included in this table is the value of vested TOPs at December 31, 2008.

Name	Termination Scenario	Pension	Value of Vested TOPs [1,2]	Total
Fischer [3]	Retirement	–	12,817,000	12,817,000
Romanow	Resignation	4,524,000	4,476,010	9,000,010
Murphy [4]	Deemed retirement	–	461,076	461,076
Thomas [5]	Deemed retirement	–	1,397,200	1,397,200
Nieuwenburg	Resignation	1,072,000	1,047,900	2,119,900

1 Does not include unvested TOPs which will vest according to the TOPs plan over 18 months for deemed retirement or over 90 days for resignation.
2 The difference between the market value of Nexen common shares at year end of $21.45/share and the grant price of TOPs, times the number of vested TOPs.
3 With Mr. Fischer's retirement on December 31, 2008, he began to receive a monthly pension benefit of $75,501.
4 Mr. Murphy would be eligible to receive a monthly pension benefit of $22,544 payable effective January 1, 2009. The option to receive a lump sum pension benefit would not be available.
5 Mr. Thomas would be eligible to receive a monthly pension benefit of $25,486 payable effective January 1, 2009. The option to receive a lump sum pension benefit would not be available.

Mr. Fischer's change of control agreement terminated on December 31, 2008 when he retired. Mr. Romanow's change of control agreement was amended in January 2009 when he was appointed President and CEO. The nature of our time-vested TOPs ensures that retiring executives maintain a significant equity interest for at least 12 months (last vesting period) after departure. Charlie Fischer maintains an equity interest that exceeds three times his annual salary.

Change of Control Agreements

Nexen has entered into change of control agreements with Messrs. Fischer, Romanow, Murphy, Thomas, Nieuwenburg and other key executives. The agreements were effective October 1999, amended in December 2000, amended and restated in December 2001, and amended and restated in September 2008. We recognize that these executives are critical to Nexen's ongoing business. Therefore, it is vital we work to retain the executives, protect them from employment interruption caused by a change of control and treat them in a fair and equitable manner. Consistent with industry standards for executives in similar circumstances, there are no restrictions on future employment or non-compete clauses in the agreements. Each year, the Compensation Committee reviews the estimated payments upon a change of control including the termination value of pension benefits due under the defined benefit pension plan and executive benefit plan.

Mr. Fischer's change in control agreement terminated on December 31, 2008 when he retired. Mr. Romanow's change in control agreement was amended in January 2009 when he was appointed President and CEO. In the event of a change of control, and subsequent termination of employment, Mr. Romanow would be deemed to retire and his pension would commence upon the later of the completion of the severance period outlined below and the attainment of age 55, without any applicable early retirement reduction.

Under these agreements, a change of control includes any acquisition of common shares or other securities that carries the right to cast more than 35% of the common share votes. Generally, it is any event that results in a person or group exercising effective control of Nexen.

If the executives terminate following a change of control, they are entitled to salary, target bonus and other compensatory benefits for the severance period specified below.

	Severance Period in Months on Change of Control	
Name	If Terminated	Upon Resignation [1]
Fischer [2]	36	36
Romanow	36	30
Murphy	30	–
Thomas	30	–
Nieuwenburg	24	–

1 Within 12 months after change of control and only if the CEO or CFO has remained an employee.
2 Mr. Fischer retired on December 31, 2008 and no longer has these entitlements.

The next table outlines the estimated incremental payments executives would be entitled to had a change of control and a subsequent termination of employment occurred on December 31, 2008. Under the agreement, bonuses would be paid at target for the full severance period. A benefits uplift, equal to 13% of base salary, would be provided in lieu of medical,

dental and life insurance coverage. In addition, the agreement provides a payment for other employee benefits and perquisites, including car allowance and savings plan contributions during the severance period, and an allowance for financial counselling, security monitoring and career transition services.

Executives would also be entitled to an incremental pension benefit relating to their salary, service and annual incentive targets over the severance period. The pension value reported below discloses the resulting lump sum payout determined according to the executive's employment arrangement. These additional pension benefits do not include any termination benefits that would be payable under the registered defined benefit pension plan and executive benefit plan if a termination or retirement occurred that was not triggered by a change of control.

Estimated Incremental Payment on Change of Control [1]

Name	Severance Period (# of months)	Base Salary ($)	Bonus Target Value ($)	Benefits Uplift ($)	Other Employee Benefits ($)	Additional Lump Sum Value of Pension [2] ($)	Accelerated TOPs Value [3] ($)	Total Incremental Obligation ($)
Fischer	36	4,095,000	3,276,000	532,350	377,200	10,269,000	836,000	19,385,550
Romanow	36	1,830,000	1,098,000	237,900	205,300	4,716,000	376,200	8,463,400
Murphy	30	1,387,500	832,500	180,375	169,150	3,780,000	355,300	6,704,825
Thomas	30	1,375,000	825,000	178,750	168,400	4,462,000	355,300	7,364,450
Nieuwenburg	24	844,000	379,800	109,720	126,940	1,690,000	209,000	3,359,460
Total		**9,531,500**	**6,411,300**	**1,239,095**	**1,046,990**	**24,917,000**	**2,131,800**	**45,277,685**

1 *Assumes a triggering event occurred at December 31, 2008.*

2 *Does not include regular termination pension values which are reported in Payments on Resignation on page 156. Benefits payable under the registered defined benefit pension plan are funded from the pension trust and payable monthly if the executive is 55 or older.*

3 *Value of TOPs that automatically vest on a change of control, based on the number of TOPs with accelerated vesting, times the closing price of Nexen common shares on the TSX on December 31, 2008 of $21.45/share, less the exercise price. The incremental value is not in addition to the value identified in the vesting provision section of the termination chart on page 156.*

CORPORATE GOVERNANCE

Nexen's board takes its duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules of the Toronto Stock Exchange (TSX), NYSE, *National Policy 58-201—Corporate Governance Guidelines and Multilateral Instrument 52-110—Audit Committees.* Except as noted below, Nexen's corporate governance practices comply with those followed by domestic companies under NYSE listing standards.

Nexen has a DSU plan for non-executive directors as described on page 137. For this plan, Nexen follows the TSX rules which, unlike the NYSE rules, exempt plans from shareowner approval where the common shares issued under the plan are purchased on the open market rather than issuing new shares.

Annually, the CEO certifies to the NYSE that he is unaware of any violation by Nexen of the NYSE's corporate governance listing standards. Nexen also provides the required Annual Written Affirmation to the NYSE. As well, our CEO and CFO have certified the quality of Nexen's public disclosure to the SEC.

All Committee mandates, including those for the Audit, Compensation and Governance Committees, and our corporate governance policy and categorical standards are available at www.nexeninc.com, and we intend to provide disclosure in this manner. Shareowners wishing to receive a copy of these documents may contact the Governance Office by telephone at 403.699.4926, or by email at governance@nexeninc.com.

GOVERNANCE COMMITTEE REPORT

The Governance Committee assists the board in overseeing implementation of our corporate governance programs. It recommends nominees for director appointments and manages the evaluation process of the board, its committees and individual directors and chairs. This oversight ensures we implement best-in-class governance practices appropriate for Nexen.

All Committee members are independent and knowledgeable on our corporate governance programs. Six members are skilled or expert in governance and board experience or diversity—expertise most relevant to the Committee's mandate.

Changes to Committee Membership in 2008

The Committee membership did not change in 2008.

Key Activities in 2008

- Recommended two new directors for appointment to the board to replace two retiring directors;
- Recommended revised share ownership guidelines for directors;
- Reviewed our annual meeting vote results;
- Recommended updates to governance documents including mandates for the board, individual directors and all board committees, the external communications policy and the corporate governance policy;
- Received regular reports on management's dialogue with governance-related stakeholders;
- Recommended a new online performance evaluation process with updated questions; and
- Consulted with Dr. Richard Leblanc, Assistant Professor of Corporate Governance, York University, on the board's performance evaluations.

The Board and Committees

The Committee reviews board and committee memberships annually, considering director independence, skills and preferences. The board is large enough to permit a diversity of views and provide expertise in running the committees, without being so large as to detract from effectiveness. Each year, a skills matrix is compiled and reviewed by the Committee. This matrix sets out areas of expertise determined to be essential to ensure appropriate strategic direction and oversight by the board. It also assists with board recruitment. The Committee's review of board experience indicates that the current mix of skills is appropriate.

Nominating a New Director for Election

The Committee identifies and assesses candidates for board appointment or nomination. Our forward-looking skills matrix has identified skills with the greatest opportunity to strengthen the board.

Before recommending a new board candidate, the Committee considers his or her performance, independence, competencies, skills and financial acumen. Character and behavioural qualities, including credibility, integrity and communication skills are considered. The Committee Chair and/or Board Chair meets with the candidate to discuss his or her interest and ability to devote sufficient time and resources to the position. Prior to nomination, potential directors must disclose possible conflicts of interest with Nexen, and background checks, as appropriate, are completed.

Mr. Hentschel and Mr. Thomson are retiring from the board at our annual meeting in April due to mandatory retirement. To fill these vacancies, two directors have been appointed to the board. Mr. Berry joined on December 8, 2008. He brings skills and expertise in international operations and business development, and health, safety and environment management. Mr. Bertram joined on January 1, 2009 and brings skills and expertise in governance and board experience, managing and leading growth, and financial acumen.

The Committee maintains an evergreen list of potential directors whose skills complement the board and whom the Committee recommends joining the board, if the individual is available when an opening arises.

Mr. Fischer resigned from the board effective December 31, 2008 upon his retirement as President and CEO. Mr. Romanow became a member of the board effective January 1, 2009 by virtue of his appointment as President and CEO. He is not independent and does not sit on any committees.

The Committee will also consider a board nominee recommended by a shareowner. See page 159 for information on communicating with the board.

Performance Evaluations

The board and management work together to foster continuous, open and honest communication, where concerns are brought forward and dealt with as they occur. In this spirit, the annual board evaluation is seen as an opportunity to review the past year and consider contributions, successes and opportunities for improvement. Visit www.nexeninc.com for a special report on our director evaluation process.

Our six-part performance evaluation review is our primary tool for determining who should be on the board. In light of this review, the board does not have a tenure policy and has flexible term limits. Nexen's average board tenure of director nominees is 8.5 years. Our retirement age is 75.

The Committee recommended a new online performance evaluation process in 2008. They also considered comments from the last evaluation to further explore executive compensation and risk management.

The board rates its overall effectiveness on a 10-point scale, where 10 is the best. The average rating was 8.9 for 2008 and 9.23 for 2007. The decline in the average score is partly explained by a change in the rating scale from fractional to whole numbers in 2008.

External Recognition and Verification

We received the following recognition for our governance practices during 2008:

- The Award of Excellence in Corporate Governance Disclosure in the 2008 Corporate Reporting Awards from the Canadian Institute of Chartered Accountants;
- Recognition from the Canadian Coalition for Good Governance for new best practices in shareholder communication and compensation disclosure;
- Finalist for the Stakeholder Communication Award at the 2008 Petroleum Economist Awards in the UK;
- The Best Corporate Governance Practices in North America by IR Global Rankings;
- Ranked 7th, with a score of 92 out of 100, in the Report on Business 2008 corporate governance rankings; and
- Current global rating of 10 out of 10 from Governance Metrics International for governance practices and disclosure.

Committee Approval

The Committee has reviewed and discussed the governance disclosure in this document, including the information in the Board of Directors section (pages 133 to 137). It has recommended to the board that the disclosure be included in the proxy circular and, as appropriate, the Form 10-K.

Submitted on behalf of the Governance Committee:

Dick Thomson, Chair
Kevin Jenkins
Anne McLellan
Eric Newell
Tom O'Neill
Francis Saville
John Willson

Ethics Policy

Under our ethics policy, all directors, officers and employees must demonstrate ethical business practices in all business relationships, within and outside of Nexen. Employees are not permitted to commit an unethical, dishonest or illegal act or to instruct other employees to do so. Our ethics policy has been adopted as a code of ethics for our principal executive officer, principal financial officer and principal accounting officer or controller.

Any waivers of, or changes to, our ethics policy must be board approved and disclosed. We have never waived any provisions of the ethics policy. Our ethics policy provides for an external integrity helpline, in place since February 1, 2005.

Nexen's ethics policy is available at www.nexeninc.com. If we amend or waive any provision of it, we will disclose this online. We also file our ethics policy and any amendments to it on SEDAR at www.sedar.com. To request a copy of the policy, contact the Integrity Resource Centre by emailing integrity@nexeninc.com or calling 403.699.6789.

Reporting Concerns

Please direct any concerns about Nexen's financial statements, accounting practices or internal controls to either:

- management or the Chair of the Audit and Conduct Review Committee (Audit Committee) as set out in the ethics policy; or
- EthicsPoint, as set out below.

Employees, customers, suppliers, partners, shareowners and other external stakeholders who have a concern are encouraged to raise it with our Integrity Resource Centre:

By mail:	Nexen Inc. 801 – 7th Avenue SW Calgary, Alberta, Canada T2P 3P7
Attention:	Integrity Resource Centre
By email:	integrity@nexeninc.com
By phone:	403.699.6789

You may also report concerns through our integrity helpline, which is a secure reporting system, operated by EthicsPoint, an independent third-party service provider. To learn more about our integrity helpline and for toll-free numbers for other countries, visit www.nexeninc.com and click on the "Integrity Helpline" link at the top of the page or access the helpline directly:

Online:	www.ethicspoint.com
By phone:	1.866.384.4277 (toll-free in North America)

Communicating with the Board

Shareowners may write to the board or any board member(s) at the following address:

By mail:	Nexen Inc. 801 – 7th Avenue SW Calgary, Alberta, Canada T2P 3P7
Attention:	Governance Office
By email:	board@nexeninc.com

We receive inquiries on many subjects daily. The board and management have developed a process to manage inquiries so that the appropriate personnel respond to them.

Nexen reviews letters and emails addressed to the board, its members or the independent directors, to determine if a board response is appropriate. While the board oversees management, it does not participate in day-to-day operations and is not normally in the best position to respond to inquiries on those matters. Those inquiries will be directed to appropriate personnel for response. The board has instructed the Governance Office to review all correspondence and, in its discretion, not forward items that are:

- not relevant to Nexen's operations, policies or philosophies;
- commercial in nature; or
- not appropriate for the board to consider.

All inquiries will receive a response from the board or management. The Governance Office maintains a log of all correspondence sent to board members. Directors may review the log at any time and request copies of correspondence received.

AUDIT COMMITTEE REPORT

See page 161 for a full report on the Audit Committee.

ITEM 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities. Based on information known to Nexen, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of Nexen's voting securities as at the date noted below.

Name and Address of Beneficial Owner	# of Shares Beneficially Owned	% of Shares Outstanding	Effective Date
Jarislowsky, Fraser Limited [1] Suite 2005, 1010 Sherbrooke Street West Montreal, Quebec, Canada, H3A 2R7	47,739,443	9.19%	January 31, 2009

1 The beneficial owner has sole voting power over 41,087,027 shares, shared voting power over 6,652,416 shares and sole power to dispose of all shares.

Security Ownership of Management

At February 12, 2009, the following directors, certain executive officers, and all directors and executive officers as a group beneficially owned the following Nexen common shares:

Name of Beneficial Owner	Number of Shares [1]	Exercisable TOPs [2]
William B. Berry	–	–
Robert G. Bertram	16,000	–
Dennis G. Flanagan	31,264	20,000
David A. Hentschel	70,925	100,000
S. Barry Jackson	72,000	–
Kevin J. Jenkins	12,415	60,000
A. Anne McLellan, P.C.	300	–
Eric P. Newell, O.C.	12,000	–
Thomas C. O'Neill	16,000	–
Marvin F. Romanow	187,432	720,400
Francis M. Saville, Q.C.	48,860	71,004
Richard M. Thomson, O.C.	92,004	150,000
John M. Willson	15,055	–
Victor J. Zaleschuk	63,152	240,000
Kevin J. Reinhart	46,483	330,800
Laurence Murphy	135,528	296,000
Roger D. Thomas	22,097	403,200
Gary H. Nieuwenburg	77,399	301,000
All Directors and Executive Officers as a Group (25 persons)	**1,058,205**	**3,818,588**

1 The number of shares held and TOPs exercisable by each beneficial owner represents less than 1% of the shares outstanding.
2 Includes all TOPs exercisable within 60 days of February 12, 2009. All TOPs held by non-executive directors are vested.

Under the terms of our TOPs plan, the board may grant options to officers and employees and, when previously allowed for, to directors. Nexen does not receive any consideration when options are granted.

Plan Category	Number of Securities to be Issued on Exercise of Outstanding TOPs	Weighted-Average Exercise Price of Outstanding TOPs	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by shareowners	24,622,290	$22/option	27,429,292
Equity compensation plans not approved by shareowners	–	–	–
Total	**24,622,290**	**$22/option**	**27,429,292**

ITEM 13.
Certain Relationships and Related Transactions, and Director Independence

RELATED PARTY TRANSACTION

As a Canadian foreign private issuer, Nexen provides the disclosure required under Item 7.B. of Form 20-F dealing with "related party transactions." Nexen did not have any related party transactions in 2008 as defined under that standard. Certain other transactions described below which are not related party transactions, involving Nexen and certain of our directors, were entered into in 2008.

DIRECTOR INDEPENDENCE

Mr. Saville was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta, until the end of January 2004. Since February 1, 2004, he has been counsel with the firm. FMC provided legal services to us in each of the last five years. Mr. Saville does not solicit or participate in these services and does not receive any portion of the fees we pay to FMC, nor is he a partner or an employee of the firm. He is independent under our categorical standards.

Ms. McLellan has been counsel with Bennett Jones (BJ), Barristers and Solicitors, Edmonton, Alberta since June 27, 2006. BJ provided legal services to us in each of the last five years. Ms. McLellan does not solicit or participate in those services and does not receive any portion of the fees we pay to BJ, nor is she a partner or an employee of the firm. She is independent under our categorical standards.

Mr. Romanow is not independent as he is Nexen's President and CEO.

Mr. Flanagan is not independent as his son is Senior Vice President, Engineering of TriAxon Resources Ltd. (TriAxon). In 2006, TriAxon acquired a company that was party to contracts with a subsidiary of Nexen. Under one of the contracts Nexen paid approximately $4.5 million to TriAxon between July and December 2006 for products purchased at market price. Accordingly, Mr. Flanagan is not technically independent as of July 1, 2007. Mr. Flanagan was not aware that the company acquired by TriAxon held contracts with Nexen. The board has determined that Mr. Flanagan's independence has not been compromised by this transaction and, accordingly, the board continues to include him in their meetings without management.

ITEM 14.
Principal Accounting Fees and Services

AUDIT COMMITTEE REPORT

The Audit Committee is responsible for appointing (subject to shareowner approval), compensating and overseeing the independent registered chartered accountants (IRCAs). The IRCAs are accountable to and report directly to the Committee, and understand that they must maintain an open and transparent relationship with the Committee, which represents our shareowners.

All Committee members are independent and knowledgeable on our financial reporting controls, and internal and external audit processes. Five members are skilled or expert in financial acumen, particularly financial accounting, reporting and internal controls—expertise most relevant to the Committee's mandate.

The Committee assists the board in overseeing Nexen's system of internal accounting and financial reporting controls, internal and external audit processes, and implementation of the ethics policy.

Management is responsible for our internal controls and financial reporting process. The IRCAs are responsible for independently auditing our: i) Consolidated Financial Statements according to Canadian and US generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States); and, ii) internal control over financial reporting according to the standards of the Public Company Accounting Oversight Board. The Committee monitors and oversees these processes.

Changes to Committee Membership in 2008

The Committee membership did not change in 2008.

KEY ACTIVITIES FOR 2008

- Met separately with management and the IRCAs to review the December 31, 2008 Consolidated Financial Statements;
- Discussed matters required by Canadian and US regulators with the IRCAs;
- Received written disclosures from the IRCAs required by US regulators;
- Discussed with the IRCAs that firm's independence;
- Discussed the scope and result of the audit with the IRCAs;
- Oversaw the compliance activities by management to report on the effectiveness of internal control over financial reporting as at December 31, 2008;
- Reviewed and approved the quarterly Consolidated Financial Statements;
- Recommended to the board that the audited Consolidated Financial Statements be included in Nexen's annual report on Form 10-K for the year ended December 31, 2008, based on the reviews and discussions referred to above; and
- Reviewed Nexen's progress on its planned transition to International Financial Reporting Standards.

Audit Partner Rotation

To comply with applicable law, the lead audit partner of our IRCAs is replaced every five years.

Sections 302 and 404 of Sarbanes-Oxley

Nexen is a voluntary filer of the Form 10-K in the US and has complied with the requirements of Sections 302 and 404 of Sarbanes-Oxley since December 31, 2004. Accordingly, Nexen is in compliance with *National Instrument 52-109—Certification of Disclosure in Issuers' Annual and Interim Filings*. In 2008, management assessed our internal control over financial reporting and concluded that it was effective as of December 31, 2008. The integrated audit report for 2008 is included in this Form 10-K.

IRCAs Engagement and Fees Billed

Before Nexen or any subsidiary engage the IRCAs for additional audit or non-audit services, the Committee must approve the engagement. The Audit Committee has the discretion to delegate to the Committee Chair, on an annual basis, the authority to pre-approve the hiring of the IRCAs for minor, time-sensitive audit services, provided any pre-approvals are presented in writing to the Committee at the next scheduled meeting. The Audit Committee has the discretion to annually delegate to one or more of its members the authority to grant pre-approvals for non-audit services provided any pre-approvals are presented in writing to the Committee at the next scheduled meeting. Since May 6, 2003, the Committee has approved all audit, audit-related, tax and other services provided by the IRCAs.

Type of Fee	Billed in 2007	Billed in 2008	Percentage of Total Fees Billed in 2008
Audit Fees			
For the integrated audit of Nexen's Consolidated Financial Statements included in our annual report on Form 10-K	2,966,000 [1]	2,812,000 [2]	
For the integrated audit of the Consolidated Financial Statements of Canexus [3]	145,000	215,600 [4]	
For the first, second and third quarter reviews of Nexen's Consolidated Financial Statements included in Form 10-Qs	90,000	110,000	
For the first, second and third quarter reviews of the Consolidated Financial Statements of Canexus [3]	45,000	45,000	
For comfort letters and submissions to commissions	153,500	3,000	
Total Audit Fees	**3,399,500**	**3,185,600**	**68%**
Audit-Related Fees – Nexen and Canexus [3]			
For the annual audits and quarterly reviews of subsidiary financial statements and employee benefit plans	828,100	1,144,700	
Total Audit-Related Fees	**828,100**	**1,144,700**	**24%**
Tax Fees – Nexen and Canexus [3]			
For tax return preparation assistance and tax-related consultation	116,400	139,800	
Total Tax Fees	**116,400**	**139,800**	**3%**
All Other Fees	110,600 [5]	216,300 [5]	5%
Total Annual Fees	**4,454,600**	**4,686,400**	**100%**

1 *Consisting of $1,366,000 to complete the 2006 audit and $1,600,000 to commence the 2007 audit.*
2 *Consisting of $936,000 to complete the 2007 audit and $1,876,000 to commence the 2008 audit.*
3 *Includes fees for Canexus Income Fund, Canexus Limited Partnership and its subsidiaries.*
4 *Consisting of $121,500 to complete the 2007 audit and $93,100 to commence the 2008 audit.*
5 *Annual renewal fees for an upstream information database used in our UK office.*

The Committee concludes that the services provided by the IRCAs as described in "All Other Fees" above maintain that firm's independence.

External Recognition and Verification

Nexen was recognized in 2008 with the Award of Excellence for Corporate Reporting in the Oil and Gas category of the Corporate Reporting Awards from the Canadian Institute of Chartered Accountants.

Committee Approval

Based on the Committee's discussions with management and the IRCAs, and its review of both their representations, the Committee recommended to the board that the audited Consolidated Financial Statements be included in Nexen's annual report on Form 10-K for the year ended December 31, 2008.

Submitted on behalf of the Audit Committee:

Tom O'Neill, Chair	Dick Thomson
Eric Newell	Kevin Jenkins
Barry Jackson	John Willson

PART IV

ITEM 15.
Exhibits, Financial Statement Schedules

FINANCIAL STATEMENTS AND SCHEDULES

We refer you to the index to Financial Statements and Supplementary Data in Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted because they are not required or applicable, or the required information is shown in the Consolidated Financial Statements or notes.

EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

2.2 Agreement for the Sale and Purchase of EnCana (U.K.) Limited, between EnCana (U.K.) Holdings Limited and Nexen Energy Holdings International Limited dated October 28, 2004 (filed as Exhibit 2.1 to Form 8-K dated October 29, 2004).

3.14 Restated Certificate and Articles of Incorporation of the Registrant dated May 20, 2005 (filed as Exhibit 3.12 to Form 10-Q for the quarterly period ended June 30, 2005).

3.15 By-Law No. 3 of the Registrant enacted December 4, 2006, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 3.15 to Form 8-K dated December 5, 2006).

3.16 Certificate and Articles of Amendment of the Registrant dated April 26, 2007 (filed as Exhibit 3.16 to Form 8-K dated April 27, 2007).

4.42 Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company providing for the issue of debt securities from time to time (filed as Exhibit 4.42 to Form 10-K for the year ended December 31, 2003).

4.43 First Supplemental Indenture dated April 28, 1998 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$200 million, 7.40% notes due 2028 (filed as Exhibit 4.43 to Form 10-K for the year ended December 31, 2003).

4.46 Third Supplemental Indenture dated March 11, 2002 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of $500 million, 7.85% notes due 2032 (filed as Exhibit 4.46 to Form 10-K for the year ended December 31, 2003).

4.47 Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of subordinated notes from time to time (filed as Exhibit 4.47 to Form 10-K for the year ended December 31, 2003).

4.48 Officer's Certificate dated November 4, 2003 pursuant to the Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issuance of US$460 million, 7.35% subordinated notes due 2043 (filed as Exhibit 4.48 to Form 10-K for the year ended December 31, 2003).

4.51 Fourth Supplemental Indenture dated November 20, 2003 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$500 million, 5.05% notes due 2013 (filed as Exhibit 4.51 to Form 10-K for the year ended December 31, 2003).

4.53 Fifth Supplemental Indenture dated March 10, 2005 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$250 million, 5.20% notes due 2015 and the issuance of US$790 million, 5.875% notes due 2035 (filed as Exhibit 10.1 to Form 8-K dated March 11, 2005).

4.55 Senior Debt Indenture dated May 4, 2007 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of senior notes from time to time (filed as Exhibit 4.1 to Form 8-K dated May 7, 2007).

4.56 First Supplemental Indenture dated May 4, 2007 to the Trust Indenture dated May 4, 2007 between the Registrant and Deutsche Bank Trust Company Americas pertaining to the issuance of US$250 million, 5.65% notes due 2017 and the issuance of US$1.25 billion, 6.40% notes due 2037 (filed as Exhibit 4.2 to Form 8-K dated May 7, 2007).

4.57 Amended and Restated Shareholder Rights Plan Agreement, dated April 29, 2008 between the Registrant and CIBC Mellon Trust Company, as Rights Agent (filed as Exhibit 4.57 to Form 8-K dated April 30, 2008).

10.41 Indemnification Agreements made between the Registrant and its directors and officers during 2002 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002).

10.42 Indemnification Agreement made between the Registrant and one of its directors, Eric P. Newell, as of January 5, 2004 (filed as Exhibit 10.42 to Form 10-K for the year ended December 31, 2003).

10.43 Credit Agreement dated as of July 22, 2005 between the Registrant and the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 28, 2005).

10.44 Guarantee dated as of July 22, 2005 as Schedule K to the Credit Agreement (filed as Exhibit 10.2 to Form 8-K dated July 28, 2005).

10.46 Indemnification Agreement made between the Registrant and one of its directors, A. Anne McLellan P.C., as of July 5, 2006 (filed as Exhibit 10.2 to Form 8-K dated July 20, 2006).

10.47 Second Amending Agreement dated July 14, 2006 to the Credit Agreement, dated as of July 22, 2005, between the Registrant and the Toronto-Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 20, 2006).

10.48 Indemnification Agreement made between the Registrant and Brendon Muller dated April 9, 2007 (filed as Exhibit 10.48 to Form 8-K dated April 12, 2007).

10.50 Pricing Agreement dated May 1, 2007 among the Registrant and Banc of America Securities LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as Underwriters (filed as Exhibit 10.1 to Form 8-K dated May 7, 2007).

10.52 Amended and Restated Agreement Respecting Change of Control and Executive Benefit Plan Entitlements with Executive Officers dated during August and September, 2008 (filed as Exhibit 10.52 to Form 10-Q for the quarterly period ended September 30, 2008).

10.53 Amended and Restated Agreement Respecting Change of Control and Executive Benefit Plan Entitlements with Kevin J. Reinhart dated as of September 16, 2008 (filed as Exhibit 10.53 to Form 8-K dated November 21, 2008).

10.54 Form of Indemnification Agreement between the Registrant and William B. Berry and Robert G. Bertram (filed as Exhibit 10.54 to Form 8-K dated December 10, 2008).

10.55 Amending Agreement dated as of December 9, 2008 to the Amended and Restated Agreement Respecting Change of Control and Executive Benefit Plan Entitlements with Marvin F. Romanow dated as of September 17, 2008 (filed as Exhibit 10.55 to Form 8-K dated December 10, 2008).

10.56* Tandem Option Plan amended June 30, 2007.

11.1* Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2008.

21.1* Subsidiaries of the Registrant.

23.1* Consent of Independent Registered Chartered Accountants.

23.3* Consent of Ryder Scott Company, L.P.

23.4* Consent of McDaniel & Associates Consultants Ltd.

23.5* Consent of DeGolyer and MacNaughton.

31.1* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1* Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2* Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1* Opinion of Internal Qualified Reserves Evaluator on National Instrument 51-101 Form F2 as required by certain Canadian securities regulatory authorities.

**Filed with this Form 10-K.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 20, 2009.

NEXEN INC.

By: /s/ Marvin F. Romanow
Marvin F. Romanow
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2009.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ A Anne McLellan, Director
A. Anne McLellan, Director

/s/ Eric P. Newell
Eric P. Newell, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Marvin F. Romanow
Marvin F. Romanow
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Brendon T. Muller
Brendon T. Muller
Controller
(Principal Accounting Officer)

/s/ Eric B. Miller
Eric B. Miller
Vice President, General Counsel
and Secretary

EXHIBIT 31.1

Certifications

I, Marvin F. Romanow, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2009

/s/ Marvin F. Romanow
Marvin F. Romanow
President and Chief Executive Officer

EXHIBIT 31.2

Certifications

I, Kevin J. Reinhart, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2009

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

Certification Of Periodic Report

I, Marvin F. Romanow, President and Chief Executive Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 20, 2009

/s/ Marvin F. Romanow
Marvin F. Romanow
President and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

EXHIBIT 32.2

Certification Of Periodic Report

I, Kevin J. Reinhart, Senior Vice President and Chief Financial Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 20, 2009

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

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